BOARD MEETING DATE: December 4, 2015 AGENDA NO. 30

PROPOSAL: Proposed Amendments to NOx RECLAIM Program (Regulation XX)

SYNOPSIS: The proposed amended Regulation XX will implement Control Measure CMB-01 of the 2012 Air Quality Management Plan and make further reductions of NOx from RECLAIM facilities. The proposed amendments implement NOx Best Available Retrofit Control (BARCT) for various equipment by establishing RECLAIM Trading Credit (RTC) reduction targets and RTC adjustment factors for year 2016 and beyond. The proposed amendments include a Regional New Source Review Holding Account for electricity generating facilities, a delay in relative accuracy testing audit due dates for specified situations, both a quarterly maximum (quicker response) and changed and new minimum price triggers for RECLAIM program review, and other administrative changes. In addition, an off-ramp for electricity generating facilities at BACT or BARCT is proposed as well as provisions that would remove RTCs from the RECLAIM Program for equipment and facilities that have shutdown. At full implementation the proposed amendments will reduce NOx RTCs by 14 tons per day by December 2022.

COMMITTEE: Stationary Source Committee, March 21, 2014, July 24, 2015, October 16, 2015, November 20, 2015, and Special Stationary Source Committee, September 23, 2015, Reviewed.

RECOMMENDED ACTION:
Adopt the attached resolution:

1. Certifying the Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM); and

2. Amending Proposed Rules 2001 – Applicability; 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx); Rule 2005 – New Source Review forRECLAIM; 2011 – Attachment C – Quality Assurance and Quality Control Procedures & Attachment E – Definitions; and 2012 – Attachment C – Quality Assurance and Quality Control Procedures & Attachment F – Definitions.

Barry R. Wallerstein, D.Env.
Executive Officer

PMF:JW:JC:GQ:MHP/KO

Introduction

The AQMD Board adopted the Regional Clean Air Incentives Market (RECLAIM) program in October 1993. The purpose of the RECLAIM program is to reduce NOx and SOx emissions through a market-based program. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with the flexibility to seek the most cost-effective solution to reduce their emissions. AQMD staff is proposing amendments to Regulation XX – RECLAIM to achieve additional NOx reductions pursuant to the 2012 AQMP Control Measure CMB-01 and state law. Specifically, the proposed amendments address requirements for Best Available Retrofit Control Technology (BARCT) in accordance with California Health and Safety (H&S) Code §40440. Reductions in NOx will help the Basin attain the federal 24-hour PM2.5 standard by 2019, and the federal ozone ambient air quality standards by 2023 and 2031. Other proposed rule amendments include clarifications and changes to the protocols.

Public Process

The rulemaking process for PAR XX – NOx RECLAIM began in the 4th quarter of 2012. In 2013, a RECLAIM Working Group was formed to discuss potential amendments to the NOx RECLAIM program.

To gather pertinent information for rule development, staff sent out Survey Questionnaires to 38 facilities, including the top 37 emitting facilities in 2011 and a cement facility which was the highest NOx stationary emission source in 2008. Since January 2013, fourteen Working Group Meetings were held to discuss potential BARCT levels for major NOx sources, the emissions inventory, potential for emission reductions, and proposals for RTC reductions. In September 2014, SCAQMD staff contracted with two consultants (Environmental Technology Services, Inc. (ETS) and Norton Engineering Consultants Inc. (NEC)) to conduct independent BARCT analyses. The consultants completed their analyses in December 2014, and staff held the 8th Working Group Meeting in January 7, 2015 to report on the consultants' findings to the stakeholders. A CEQA and Socioeconomic scoping session was held on January 8, 2015.

From January to March 2015, staff reviewed the consultants' analyses and addressed comments received in response to the CEQA and Socioeconomic scoping session. Staff also extended the contract for NEC to allow time to produce confidential proprietary information reports for each refinery, and this task was completed in April 2015.

In addition to the thirteen Working Group Meetings, there were over 50 meetings held with various stakeholders individually or in groups to discuss the BARCT analysis and the proposed allocation reduction distribution (shave) methodology. Staff also met with a number of air pollution control manufacturers to discuss control technologies, and invited the manufacturers to write manuscripts and give presentations at the 2014 Air & Waste Management Association annual conference in Long Beach. Several refinery representatives participated in the discussions at the conference.

A Public Workshop was conducted on July 22, 2015, a Public Consultation Meeting was conducted on September 29, 2015, the draft Program Environmental Assessment was released on August 14, 2015 for 53 days of public comment, and the draft socioeconomic analysis was released on September 9, 2015. Five Stationary Source Committee meetings were held: March 21, 2014; July 24, 2014; October 14, 2015; a special session on September 23, 2015 requested by industry devoted to RECLAIM; and November 20, 2015. The staff presentations for the three most recent Stationary Source Committee meetings are shown in Attachments K (September 23, 2015), L (October 14, 2015), and M (November 20, 2015). The industry and environmental group coalition presentations from the September 23, 2015 Stationary Source Committee are in Attachments N and O.

NOx RECLAIM Facilities

There were 276 facilities in RECLAIM as of June, 2011. These facilities either elected to enter the program or had NOx emissions greater than or equal to four tons per year in 1990 or any subsequent year. The distribution of the 2011 audited emissions and RTC allocations by industry type are shown in Figures 1 and 2, respectively.

FIGURE 1
Distribution of 20 tpd NOx Emissions (End of Compliance Year 2011)

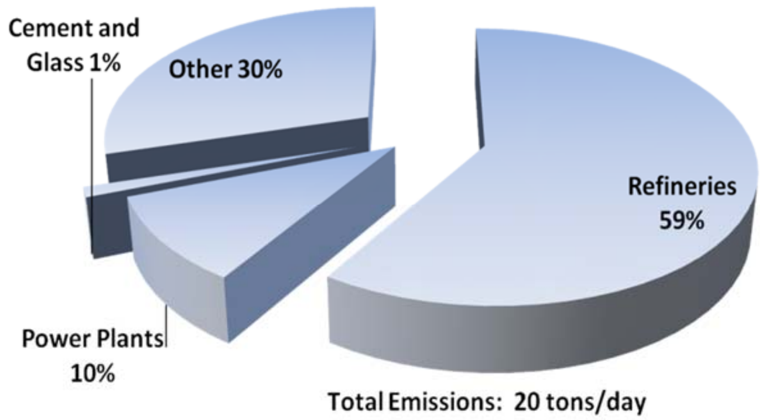
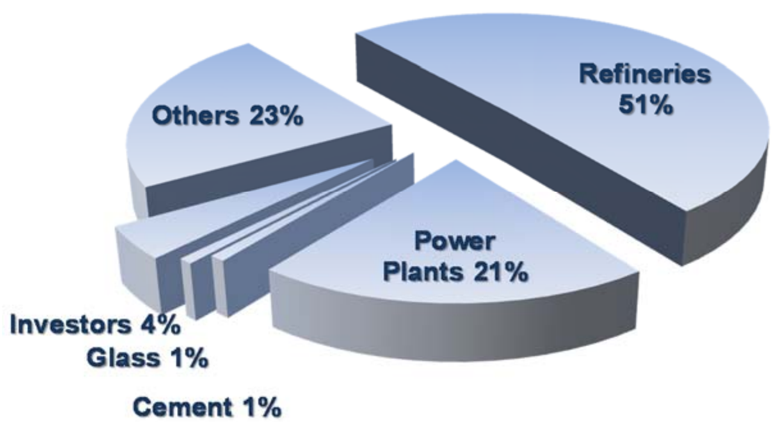


FIGURE 2
Distribution of 26.5 tpd RTC Holdings (End of Compliance Year 2020)



The top 37 facilities emitted 17.10 tpd NOx in 2011, more than 85% of emissions. The NOx emissions from RECLAIM facilities are generated from a wide range of equipment, and the top NOx emitting sources at the 37 facilities are refinery coke calciners, refinery fluidized catalytic cracking units, refinery and non-refinery gas turbines, refinery boilers and heaters, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces, internal combustion engines, and refinery sulfur recovery and tail gas incinerators. Cement kilns were the highest emitting stationary NOx source in 2008. The 2011 inventory did not include the cement kilns in the inventory since they were non-operational and subsequently shut down in 2012. However, staff did identify a new BARCT level for this operation and included the equivalent amount in the projected remaining BARCT-level NOx emissions in 2023.

Staff Proposal
The descriptions of the staff proposal below includes staff's rationale for the proposed rule amendments. The descriptions also include key changes made to the proposal as a result of comments and feedback on key issues received throughput the rulemaking process.

BARCT Levels
When the NOx RECLAIM program was first adopted, the NOx RECLAIM facilities were issued NOx annual allocations (also known as facility caps), which declined annually from 1993 until 2003 and remained constant after 2003. The annual allocations issued to the NOx RECLAIM facilities reflected the levels of Best Available Retrofit Control Technology (BARCT) envisioned to be in place at the RECLAIM facilities, and were the result of a BARCT analysis conducted in 1993. As previously mentioned, BARCT reassessment is required by California Health & Safety Code (H&SC) §40440 to assess the advancement in control technology, to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach, and that emission reductions from the program fully contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). There was a BARCT reassessment for NOx in 2005 and another for SOx in 2010, and the RECLAIM rules were subsequently amended to reduce the facility annual allocations. The 2012 AQMP Control Measure CMB-01 identified a new group of RECLAIM NOx emitting equipment that needed to be subject to a BARCT analysis. This new BARCT analysis began in October 2012.

Over the next few years the BARCT analysis resulted in the BARCT levels, incremental emission reductions by 2023, costs, and cost effectiveness shown in Table 1. For the refinery sector, new BARCT levels are proposed for fluid catalytic cracking units, boilers/heaters >40 mmbtu/hr, gas turbines, coke calciners, and sulfur recovery and tail gas incinerators. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal melting furnaces >150 mmbtu/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for electricity generating facilities (EGF) given that the vast majority of equipment in this sector is already permitted at BARCT or BACT.

TABLE 1
Summary of Proposed new BARCT Since 2005 NOx RECLAIM Amendments

	2015 BARCT	Incremental Emission Reductions from 2000/2005 BARCT (tpd)	Number of Affected Facilities	Estimated No of Control Devices	Incremental Cost Effectiveness (thousand dollars/ton)
Refinery Sector					
FCCUs	2 ppmv	0.43	5	5 SCRs (or 2 SCRs + 3 LoTOx/WGS)	3 - 13
Boilers and Heaters	2 ppmv	0.94	8	73 SCRs	28
Refinery Gas Turbines	2 ppm	4.14	5	7 SCRs and adding catalysts to 4 SCRs	1 - 3
Coke Calciner	10 ppmv	0.17	1	1 UltraCat (or 1 LoTOx/WGS)	22 - 35
SRU/TG Incinerators	2 ppmv	0.32	4	6 SCRs (or 1 SCRs + 5 LoTOx/WGS)	28 – 40
Refinery Total		**6.00**		**91 SCRs + 1 UltraCat (or 83 SCRs and 9 LoTOx/WGS) and adding catalysts to SCRs**	**10 - 17**
Non-Refinery Sector					
Glass Melting Furnaces	80% reduction	0.24	1	2 SCRs (or 1 UltraCat)	3 – 7
Sodium Silicate Furnace	80% reduction	0.09	1	1 SCR (or 1 UltraCat)	4 – 8
Metal Heat Treating	9 ppmv	0.56	1	1 SCR	3 – 4
Gas Turbines (non-OCS)	2 ppmv	1.04	3	14 SCRs	5 – 36
ICEs (non-OCS)	11 ppmv	0.84	7	16 SCRs	5 – 8
Non-Refinery Total (w/o Cement Kilns)		**2.77**		**34 SCRs (or 31 SCRs and 2 UltraCat)**	**6 - 7**
Overall		**8.77**		**125 SCRs + 1 UltraCat (or 114 SCRs + 9 LoTOx/WGS + 2 ultracat)**	**9 – 14***

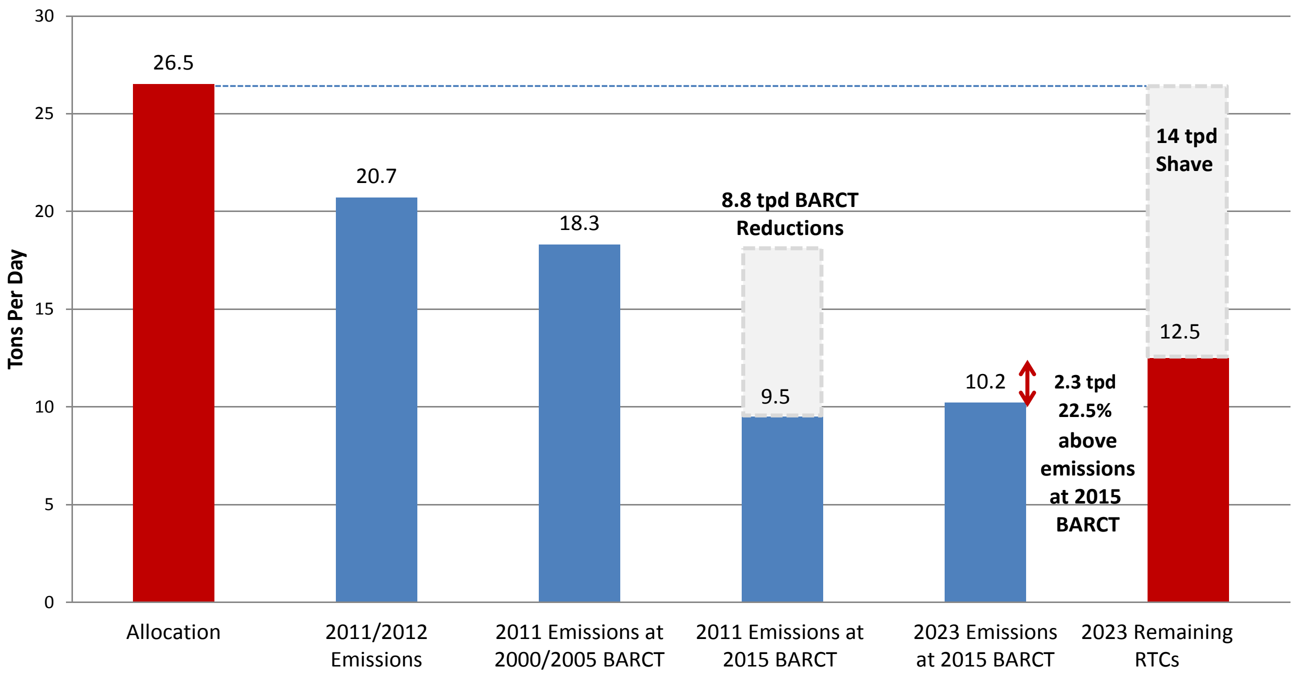
***overall average cost effectiveness**

The total cost of the proposed amendments ranges from $728 million to $1.1 billion, and the overall average cost effectiveness of the emission reductions range from $9 K to $14 K per ton NOx reduced.

RTC Reductions

As shown in Table 1, the total BARCT-equivalent emission reductions are 8.77 tpd (6.00 tpd for the refinery sector and 2.77 tpd for the non-refinery sector.) Due to projected growth, the remaining emissions in 2023 at these proposed 2015 BARCT levels would be 10.23 tpd (2.76 tpd for the refinery sector and 7.47 tpd for the non-refinery sector.) A 10% compliance margin has been added to the 2023 remaining emissions. In addition, the remaining emissions from shutdown glass and cement facilities have been added at BARCT levels, as well as the emissions for new facilities entering RECLAIM program since 2005, thereby adding to the total remaining emissions. Furthermore, an adjustment has been included to account for uncertainties that arose in the BARCT analysis and for additional 2011 activity level adjustments. This results in total proposed NOx RTC reductions of 14 tpd from the current RTC holdings of 26.5 tpd in 2023. The remaining RTCs for the NOx RECLAIM universe would be 12.5 tpd (26.5 tpd – 14 tpd = 12.5 tpd), which is 2.3 tpd or 22.5% above the projected remaining emissions from RECLAIM NOx sources in 2023. See Figure 3. It should be noted that the 2.3 tpd includes the compliance margin as well as activity and uncertainty adjustments.

FIGURE 3
Audited Emissions and RTC Holdings



Staff is proposing to distribute the 14 tpd NOx RTC reductions to 56 facilities and investors that hold 90% of the 26.5 tpd RTCs. Investors are grouped with the refineries and treated as a facility for shave purposes. The remaining 219 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was limited or no new BARCT for the types of equipment and operations at these facilities. The current proposal is to weight the amount of shave considering the technology available to different facility types and is summarized below:

66% shave for 9 refineries and 15 investors;

49% shave for 21 electricity generating facilities;

49% shave for 26 other major facilities; and

0% shave for 219 remaining facilities.

The 2023 remaining emissions after installing BARCT, the RTC holdings after the shave, and the surplus or deficit RTCs after the shave for each industry sector are presented in Table 2. After the shave, the 9 refinery facilities, the investors, and the 21 electricity generating facilities would have surplus RTCs. Note that even though no new BARCT is proposed for the electricity generating facilities, Table 2 shows that their post-shave holdings are still projected to exceed their NOx emissions. Some facilities in the 26 non-electricity generating facilities and the 219 remaining facilities would not be subject to any shave; however their emissions would grow above their current RTC holdings and they would have to purchase RTCs from other industry sectors to reconcile their projected emissions. Overall, there is a projected net 2.3 tpd of surplus RTCs for the entire RECLAIM universe.

TABLE 2
Summary of 2023 RTC Holdings and 2023 Emissions After BARCT

	9 RefineryF acilities	**15 Investors**	**21 Electricity Generating Facilities**	**26 Non-Electricity Generating Facilities**	**219 Other Facilities**	**Net Total**
Current RTC Holdings (tpd) (note)	14.15	0.42	5.63	3.45	2.86	26.5
% Shave	66%	66%	49%	49%	0%	
RTC Holdings After Shave (tpd)	4.81	0.14	2.87	1.76	2.86	12.5
2023 Emissions After BARCT (tpd)	2.76	0	2.04	1.93	3.5	10.2
Surplus or Deficit RTCs (tpd)	2.05	0.14	0.83	(0.17)	(0.64)	2.3

Note: RTC Holdings as of September 22, 2015

The 14 tpd RTC reduction is proposed to be implemented over a 7-year period from 2016 to 2022 to help the Basin meet the PM2.5 standard deadlines as well as the ozone standards in 2023 and 2031. The implementation schedule for NOx RTC reductions would be:

2016 – 4 tons per day
2018 – 2 tons per day
2019 – 2 tons per day
2020 – 2 tons per day
2021 – 2 tons per day
2022 – 2 tons per day

Over the past five years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5 tpd to 8 tpd, and thus staff is proposing a 4 tpd RTC reduction in

2016. Additional BARCT implementation will take about 2 – 4 years for planning, permitting, and construction, so the proposal assesses the remaining shave of 10 tpd over five years from 2018 to 2022.

Price Triggers

Safeguards for the integrity of the RECLAIM program have been in place for the last several years in the form of a price trigger. The current price trigger is $15,000 per ton based on a 12-month rolling average. If the trigger is exceeded then the Executive Officer reports to the Governing Board with recommendations to stabilize the market.

During this rulemaking process the following points have been made:

- The current price trigger has never been adjusted for inflation.
- Depending on the impacts, the current program safeguard may not respond quickly enough to adequately protect the RECLAIM program.
- There is not a minimum price trigger that could be used to encourage additional NOx reductions.

To address the abovementioned points, the current 12-month rolling average trigger has been proposed to change from $15,000 to $22,500 per ton (discrete credits). For a quicker response a trigger level of $35,000 per ton, also for discrete credits, has been added for a 3-month rolling average. If RTC prices exceed either of these levels, a report to the Board and a program review are required. Also included in the proposal is a new 12-month rolling average for Infinite Year Block (IYB) RTCs of $200,000 per ton. If credit prices are lower than this amount, then a report to the Board is also required.

The abovementioned report would include a commitment and schedule to conduct a more rigorous cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program.

Regional NSR Holding Account

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state New Source Review (NSR) program requirements. One of the requirements is to ensure that the facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. For a RECLAIM facility existing prior to the adoption of the RECLAIM program, the amendments made in June 3, 2011 required the RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but did not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocation plus non-tradable credits.

However, a new RECLAIM facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any unused RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter. To remedy this burdensome RTC holding requirement for new electricity generating facilities (EGF) that cannot change their allowable NOx emissions in their Facility Permit, staff is proposing a Regional NSR Holding Account. Proposed changes in Rule 2005 would assure that the RTCs in the Account would only be used the for the purpose of complying with the NSR requirements

State of Emergency Related to Electricity Generating Facilities

There is a distinct possibility that EGFs' ability to comply with their NOx RECLAIM requirements would be compromised in a State of Emergency declared by the Governor. To alleviate this potential problem from occurring it is proposed that impacted EGFs would have access to various sources of RTCs. For example, rule provisions have been added to convert Non-tradable/Non-usable RTCS to Non-tradable/usable RTCs during a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries. Thus during a State of Emergency, the current compliance year Non-tradable/Non-usable NOx RTCs held by any electricity generating facilities that generate and distribute electricity to the grid system affected by the State of Emergency may be used to offset emissions after completely exhausting their own Tradable/Usable NOx RTCs.

If such a facility has completely exhausted their Non-tradable/Non-usable NOx RTCs, the EGF owner or operator may apply for the use of the NOx RTCs in the Regional NSR Holding Account. The use of such RTCs in this Account would be based on availability at the end of each quarter. The owner or operator of each electricity generating facility requesting NOx RTCs from the Regional NSR Holding Account would be required to submit a written request to the Executive Officer specifying the amount of RTCs needed and the basis for requesting the required amount.

Electricity Generating Facilities Opting-Out of RECLAIM

EGF owners and operators have provided compelling reasons that, given the extent of the proposed shave and the unique conditions facing the electricity generation sector, EGFs should be given the option to exit NOx RECLAIM. SCAQMD staff agree that it appropriate to provide this option.

These provisions would allow the owner or operator of an EGF to opt out of the NOx RECLAIM program. To achieve this exit from NOx RECLAIM, a plan submitted by the EGF would need to demonstrate that at least 99 percent of the EGF's NOx emissions for the most recent three compliance years are at current BARCT or BACT. The proposed rule provisions specify how the New Source Review requirements would be met, how RTCs will be handled, and that Facility Permit amendments would be required to ensure that BARCT or BACT levels would be maintained. The EGF operator would need to comply with any source specific rule limits as quickly as possible, but no later than three years after approval of their opt-out plan. The owner or operator of multiple EGFs under common control would have one opportunity to apportion the NOx limits among its facilities. Monitoring, reporting, and recordkeeping requirements of Rule 2012 and its associated protocols would continue to apply unless the Executive Officer approves an alternative plan that is sufficient to determine compliance with all applicable rules.

RTC Reduction Exemption

The RECLAIM program currently includes an exemption for facilities that meet certain very stringent requirements. Given that no facilities in the RECLAIM program applied for the exemption, the staff proposal removes this provision.

Facility and Equipment Shutdowns

Currently, RTCs resulting from permanently shut down facilities have been sold and reintroduced back into the RECLAIM program. This source of RTCs does not provide an adequate incentive for the remaining facilities to reduce their NOx emissions and may incentivize owners to shut down their facilities. On this basis, staff is proposing to have the RTCs retired from the larger NOx emitting facilities that have shut down. This change is needed to achieve equivalency to command and control rules.

Specifically, the proposal will have the RTCs retired from complete facility closure or equipment shutdowns that represent twenty-five percent or more of a facility's emissions for any quarter within the previous 2 compliance years. This would apply to any facility listed in proposed Tables 7 or 8 of Rule 2002 (i.e., the larger NOx emitting facilities). Permits associated with the equipment being shut down would be surrendered, and the RTCs for future years would be retired from the RECLAIM program.

Future Electricity Demands

Board Resolution language has been introduced to direct staff to follow-up on the extent and impact that future power demands may have on EGFs. This language would direct staff to monitor trends in NOx emissions from EGFs that could be attributable to increasing reliance on renewable sources of energy or increasing market penetration of electric vehicles. On or before April 30, 2017, and on an annual basis thereafter, staff will meet with a working group that includes representatives from the electricity generating industry to discuss and quantify any potential increases in NOx emissions resulting from these trends. On or before June 30, 2017, and on an annual basis thereafter, staff will report to the Stationary Source Committee regarding any NOx emission increases from these facilities attributable to increased renewable energy or electric vehicle utilization, relative to the basin-wide NOx and greenhouse gas reduction benefits from these technologies.

If staff finds that increased power supply intermittency and/or power demand are leading to increased NOx emissions from EGFs, but that these NOx emission increases are outweighed by the NOx and GHG reduction benefits of renewable energy and electrified mobile sources, then no later than 60 days after making that determination staff will make recommendations to the Stationary Source Committee on proposed program amendments designed to assist the affected EGFs with complying with their NOx RECLAIM obligations

Other Proposed Administrative Amendments

Miscellaneous other minor changes to the RECLAIM program are also included in the staff proposal:

- 5-Year Limitation on Amending Annual Emission Reports
- New procedures and criteria for postponing the due date of semi-annual or annual assessments
- Various clarifications and minor edits

Other Key Issues/Comments from the Public

There are a number of key issues regarding the proposed amendments that have been raised and discussed during the rulemaking process. These issues include:

- Emission reduction target, including the amount and timing of NOx RTC reductions
- Equipment life assumptions
- Gap between allocations and actual emissions
- Future electricity demand
- EGF opt-out of RECLAIM;
- Retirement of RTCs from facility and equipment shutdowns
- Potential dismantling of cap and trade underpinnings of RECLAIM

Staff's responses to these issues are described below.

Emission Reductions

SCAQMD staff have significant concerns that proposals with less than 14 tons per day (TPD) of RTC reductions would not meet state law requirements for BARCT and command and control equivalency. The regulated community proposes that 8.77 tpd is the BARCT adjustment and that the additional 5.23 tpd of reductions proposed by staff goes beyond BARCT. On the other hand, environmental groups feel that all NOx reductions are needed to attain the ambient air quality standards. Therefore, the total reductions should be 14.8 tpd, including the 0.8 tpd that covers the potential uncertainties in the BARCT analysis.

With regard the regulated community's proposal, staff believes that in order to demonstrate equivalency with command and control regulations, there must be 10.23 tpd remaining emissions in 2023. After adding allowances for uncertainty, growth, and compliance margin, this equates to a shave of 14 tpd which is the amount needed to achieve BARCT. It does not go beyond BARCT.

In considering NOx emission reductions while maintaining the stability of a functioning market, staff feels that a 0.8 tpd adjustment to account for uncertainty in the BARCT analysis is appropriate. Specifically, this 0.8 tpd is intended to cover the differences in engineering assumptions between staff and the consultant that reviewed staff's analysis, and other uncertainties that arose during the BARCT analysis.

Timing of the RTC reductions

According to the regulated industry the initial RTC reduction of 4 tpd in 2016 is excessive. They feel that the timing of the RTC reductions should be delayed and back-loaded in the later years.

Staff believes that the 4 tpd RTC reductions proposed for 2016 could be achieved merely by removing excess, unused RTCs from the market without the need to install control equipment. Actual NOx reductions by control equipment would not be needed until 2018. A uniform reduction from that point on will help to avoid concurrent demand for materials, contractors and other resources at the end shave.

Equipment Life

The regulated community have raised concerns that the use of the discounted cash flow (DCF) method and that a 25-year useful life overstates the cost effectiveness of controls. They feel that ten years is more appropriate.

Staff provides both DCF and levelized cash flow (LCF) cost effectiveness estimates. Refineries have acknowledged that the equipment in question frequently lasts 25 years. This lifespan is consistent with assessments by U.S. EPA and other agencies. A 10-year life, as proposed by the regulated community, assumes that a rule significantly affecting this equipment is adopted in 10 years AND that all equipment investments made become obsolete at that time. This is not a reasonable assumption.

Staff is using the same cost effectiveness threshold of $50,000/ton that was approved for SOx RECLAIM. Moreover, the current NOx cost-effectiveness value has not been adjusted for inflation over the last 7 years.

The average incremental cost effective for this proposed amendment is:

- Refinery Sector: $10,000/ton - $17,000/ton
- Non-Refinery Sector: $9,000/ton - $14,000/ton

The Gap between Allocations and Actual Emissions
The regulated industry have commented that the gap between allocations and actual emissions should be much larger than what is being proposed. They feel that this gap is important for the market to function, including a compliance margin, growth, investor holdings, and RTCs for new facilities and structural buyers.

The staff proposal includes a 10% compliance margin, adjustments, and growth projections for existing and new businesses. The resulting 22.5% gap is sufficient and consistent with past gaps in a well-functioning market.

Future Electricity Demands
EGFs have commented that there will be a significant adverse impact on achieving compliance with NOx RECLAIM due to future increases in electrical demand. In response to this concern, Board Resolution language has been introduced to require staff to follow-up on the extent and impact that future power demands may be have on the EGFs relative to RECLAIM. This language directs staff to monitor trends in NOx emissions from EGFs that could be attributable to increasing reliance on intermittent renewable sources of energy or increasing market penetration of electric vehicles. On or before April 30, 2017, and on an annual basis thereafter, staff will meet with a working group that includes representatives from the electricity generating industry to discuss and quantify any potential increases in NOx emissions resulting from these market trends. On or before June 30, 2017, and on an annual basis thereafter, staff will report to the Stationary Source Committee regarding any NOx emission increases from these facilities attributable to increased renewable energy or electric vehicle utilization, relative to the basin-wide NOx and greenhouse gas reduction benefits from these technologies.

If staff finds that increased power supply intermittency and/or power demand are leading to increased NOx emissions from EGFs, but that these NOx emission increases are outweighed by the NOx and GHG reduction benefits of renewable energy and electrified mobile sources, then no later than 60 days after making that determination staff will make recommendations to the Stationary Source Committee on proposed program amendments designed to assist the affected EGFs with complying with their NOx RECLAIM obligations. Note that the proposal to provide an option for EGFs to opt out of RECLAIM could help to address this issue.

EGF Opt-out of RECLAIM
Industry representatives other than the EGFs have questioned why EGFs would be the only industrial sector allowed to opt-out of RECLAIM.

For the following reasons staff feels that due to the unique situation of EGFs, they should be the only sector allowed to exit RECLAIM at this time:

- The electrical grid system has changed over time such that EGF's must respond when asked to provide grid stability
- EGFs are highly regulated and thus have or will modernize (i.e. Once-Through Cooling Regulation)
- Most units already at BARCT or BACT
- EGFs provide an essential public service - other essential public services exempt from RECLAIM
- EGFs need to hold extra RTCs to meet NSR and/or resource adequacy requirements

Retirement of RTCs from facility and equipment shutdowns
The regulated community has questioned why RTCs should be retired from facilities that have permanently shut down their equipment. They feel that these RTCs should remain in the RECLAIM program in order to maintain market stability.

Staff's response is that under command and control shutdown credits are significantly discounted to BACT and are based on the last 2 years of operation. Currently under RECLAIM if a facility shutdowns, there is no such discount of credits. In addition, these credits, if not removed from the program, reduce the incentive to implement cost-effective controls that would be required under command and control.

Potential dismantling of cap and trade underpinnings of RECLAIM
The Los Angeles County Business Federation (BizFed) has commented (on November 18, 2015) that the November 4, 2015 proposed rule language (1) allowing EGFs to opt-out RECLAIM, and (2) requiring the retirement of RTCs from permanent facility and equipment shutdowns would constitute a significant step towards the dismantling the cap and trade structure of RECLAIM. As such they requested additional Working Group meetings to discuss the impacts of the proposed rule language and its impact on RECLAIM.

Staff has responded by conducting two Working Group meetings (November 24 and 30, 2015) focused on the recent proposed rule language amendments. Staff does not believe the amendments in any way dismantle the market-based structure of the RECLAIM program. If all identified cost-effective controls are implemented, there will still be sufficient surplus RTCs to allow the market to function as it has in the past. Allowing the EGFs to opt-out, as stated above, is in recognition of their unique circumstances and their limited ability to implement additional controls. The retirement of RTCs upon permanent facility or equipment shutdown is necessary to maintain equivalency with command and control regulations.

California Environmental Quality Act (CEQA) Analysis
Pursuant to California Environmental Quality Act (CEQA) Guidelines §15252 and §15168 and SCAQMD Rule 110, the SCAQMD has prepared a Program Environmental

Assessment (PEA) for proposed amended Regulation XX. Only the topics of air quality and GHGs, hydrology (water demand), and hazards and hazardous materials (due to ammonia transportation) were identified in the Draft PEA as exceeding the SCAQMD's significance thresholds. The Draft PEA was circulated for a 53-day public review and comment period from August 14, 2015 to October 6, 2015. Eight comment letters were received from the public relative to the Draft PEA and responses to the comments have been prepared and are included in the Final PEA.

Subsequent to release of the Draft PEA for public review and comment, modifications were made to the proposed project and some of the revisions were made in response to verbal and written comments received. These modifications are reflected in the Final PEA as underlined/ ~~strikethrough~~ text. Staff has reviewed the modifications to the proposed project and concluded that none of the modifications constitute: 1) significant new information which discloses that a significant new environmental impact would result from the project or that there would be a substantial increase in the severity of an environmental impact; or 2) provide new information of substantial importance relative to the Draft PEA. As a result, the modifications do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5. Therefore, the document is a now a Final PEA and is included as an attachment to this Governing Board package.

Socioeconomic Analysis

A socioeconomic assessment has been conducted as part of this rulemaking process. The report can be found in Attachment J of this Board package. Key findings from the assessment are reported below.

The proposed amendments would reduce (or "shave") 14 tons per day (tpd) of NOx RECLAIM Trading Credits (RTCs) by the year 2023. The proposed shave would affect the current RTC holdings for 56 out of 275 RECLAIM facilities and investors. The 56 affected facilities would include 9 major refinery facilities, 21 electrical generating facilities, and 26 other top emitting non-refinery facilities which represent manufacturing, mining, oil and gas exploration, utilities, amusement and recreation industries, and a military facility. The remaining 219 facilities could be potentially affected if the proposed shave would induce changes in NOx RTC prices. These facilities represent a range of industries, but are largely comprised of manufacturing, mining, oil and gas exploration, and utilities industries.

Cost Impacts

The proposed amendments are assumed to induce full BARCT installation by 2023 at the 9 refineries and 11 non-refinery facilities where the 2015 BARCT analysis identified cost-effective controls for their major NOx emission sources. This assumption is made to arrive at the most conservative (i.e., maximum) compliance cost estimates. In reality, the RECLAIM program affords facilities with compliance flexibility so that the actual costs may be lower if a facility identifies any other more cost-effective alternatives to remain in compliance, such as RTC purchases and operational changes. Total compliance cost associated with control equipment installation by 9 refineries and 11 non-refinery facilities would range from $728 million to $1.1 billion in present worth values. However, these estimates do not consider the possibility that these 20 facilities could potentially sell surplus NOx RTCs gained after control installation, which would then offset control installation costs.

The proposed shave could potentially affect facilities with no identified cost-effective controls in two ways. First, 36 of these facilities would be subject to the proposed shave, and some of them would need to buy additional NOx RTCs to reconcile actual emissions. Second, all facilities could potentially pay a higher price for NOx RTCs that they purchase each year for compliance. Additionally, higher NOx RTC prices could be potentially induced by the opt-out of any electricity generating facilities or the shut-down of any RECLAIM facilities that regularly sell their surplus credits. Furthermore, under the proposed amendments, the 12-month rolling average price trigger would be raised to $22,500 per ton (discrete credits), thus potentially allowing NOx RTC prices to increase further before non-tradable/non-usable NOx RTCs are converted to tradable/usable NOx RTCs; however, the proposed addition of a 3-month rolling average price trigger of $35,000 per ton (discrete credits) would ensure short-term price stability during the period of proposed phase-in shave. Total incremental compliance cost associated with RTC purchases over the course of 25 years is estimated to range from $19 million—if discrete NOx RTC prices remain the same—to $500 million—if the average annual discrete NOx RTC prices increase to $22,499/ton for a total of 25 years and none of the affected facilities pursue any other more cost-effective compliance options. (Cost estimates are expressed in 2014 dollars.)

Job Impacts

Assuming that the proposed amendments would induce full BARCT installation by 2023 and the 9 refineries and 11 non-refinery facilities would incur the high-end estimated costs, it is projected that about 20 jobs on the net would be created on an annual average between 2018 and 2035, and about 140 net jobs would be foregone when the analysis horizon is extended to 2043. (Note that jobs foregone may include either losses of existing jobs or projected additional jobs not created.) The difference is because the majority of jobs, mostly in the construction sector, would be created at the beginning of the analysis period (2018-2022) when control installation is assumed to take place. Despite having a large share of the total compliance cost, the refinery industry is projected to have fewer jobs forgone relative to other industries with similar magnitude of cost impact due to the fact that the industry is the most capital-intensive. As such, less labor would be required to produce the same amount of products or services. Note that the projected job impact would be more positive if the 9 refineries and 11 non-refinery facilities would sell their surplus NOx RTCs to offset control installation costs.

Regarding the incremental compliance cost that could be potentially incurred by the rest of NOx RECLAIM facilities, the associated job impacts have been estimated under various scenarios of discrete NOx RTC prices. If prices remain the same, little job impact is expected due to the proposed amendments. If the average annual discrete NOx RTC prices increase to $24,999/ton and none of the affected facilities pursue any other more cost-effective compliance options, then about 40 jobs on the net would be foregone annually between 2023 and 2035. However, this latter price scenario is unlikely to occur, particularly if the 9 refineries and 11 non-refinery facilities would sell surplus NOx RTCs after control installation and thus increase the market supply of NOx RTCs.

Costs of Command-and-Control Compared to RECLAIM

RECLAIM allows facilities to use the least costly option to remain in compliance. Unlike command-and-control regulations where every source has to be controlled to the same emission standard, RECLAIM facilities can pursue operational changes or purchase RTCs from investors and other facilities with surplus credits in lieu of upgrading existing control equipment or installing new control equipment. Therefore, by design, total costs to install controls under the RECLAIM program since its adoption have been less than they would have been under command and control. The stream of cost-savings for any RECLAIM facility would only be reduced when, at a point in time, it becomes more economical for the facility to install the control equipment that would have been required under command-and-control. However, the future cost-savings may not be completely eliminated by control installation as long as the facility is able to sell surplus RTCs to offset control installation costs. Therefore, the costs of RECLAIM in the aggregate, following implementation of staff's proposal, would not exceed the costs of command and control regulations.

Implementation and Resources

It is expected that there will be a workload increase due to applications submitted for installing new control equipment or retrofitting/modifying existing processes and there might be an increase in RTC trading activities. However, current AQMD resources are adequate to implement the proposed amended rules.

Attachments

A. Summary of Proposal
B. Summary of Positions on Key Issues
C. Rule Development Process
D. Key Contact List
E. Resolution
F. Attachment 1 to the Resolution (Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan)
G. Proposed Amended Regulation XX - RECLAIM
H. Staff Report
I. Program Environmental Assessment

J. Socioeconomic Report
K. Staff Stationary Source Committee Presentation (Special Session) – September 23, 2015
L. Staff Stationary Source Committee Presentation – October 16, 2015
M. Staff Past Stationary Source Committee Presentation – November 20, 2015
N. Stationary Source Committee Presentation (Special Session) – September 23, 2015: Industry RECLAIM Coalition
O. Stationary Source Committee Presentation (Special Session) – September 23, 2015: Environmental Groups

ATTACHMENT A
SUMMARY OF PROPOSAL

Electricity Generating Facilities Opt-out of NOx RECLAIM (Rule 2001 - paragraphs (g)(1) to (g)(4) and subparagraphs (i)(1)(K) and (i)(2)(O))

These provisions would allow the owner or operator of an electricity generating facility (EGF) to opt out of the NOx RECLAIM program. An opt-out plan would need to demonstrate that at least 99 percent of the EGF's NOx emissions for the most recent 3 compliance years are at current BARCT or BACT. These proposed provisions specify how New Source Review requirements would be met, how RTCs will be handled, and that Facility Permit amendments would be required to ensure that BARCT or BACT levels would be maintained. The EGF operator would need to comply with any source specific rule limits as quickly as possible, but no later than 3 years after approval of their opt-out plan. The owner or operator at multiple EGFs under common control would have one opportunity to apportion the NOx limits among its facilities. Monitoring, reporting, and recordkeeping requirements of Rule 2012 and its associated protocols would continue to apply unless the Executive Office approves an alternative plan that is sufficient to determine compliance with all applicable rules.

New Proposed BARCT Levels (Rule 2002 - Table 6 and subparagraph (f)(1)(L))

- 2 ppmv for FCCUs, Refinery and Non-Refinery Gas Turbines, Refinery Boilers and Heaters greater than 40 mmbtu/hr, SRU/TGs, cement kilns and coal fired boiler
- 9 ppmv for Metal Heat Treating
- 10 ppmv for petroleum coke calciner
- 80% reduction for glass melting furnaces and Sodium Silicate Furnace, and
- 11 ppmv for internal combustion engines

Proposed RTC Reductions and Use of Non-tradable/Non-usable NOx RTCs (Rule 2002 - subparagraphs (f)(1)(B), (f)(1)(C), (f)(1)(D), Table 7, and Table 8)

These provisions distribute the 14 tpd NOx RTC reductions to 56 facilities and investors that hold 90% of the RTCs. Investors are grouped with the refineries and treated as a facility for shave purposes. The remaining 219 facilities that hold 10% of the RTCs are not proposed to be shaved because there was limited or no new BARCT for the types of equipment and operation at these facilities.

The overall NOx RTC reductions of 14 tpd are expected to be achieved incrementally from 2016 to 2022, according to the following implementation schedule:

- 2016 – 4 tons per day
- 2018 – 2 tons per day
- 2019 – 2 tons per day
- 2020 – 2 tons per day
- 2021 – 2 tons per day
- 2022 – 2 tons per day

Proposed Price Triggers (Rule 2002 - subparagraphs (f)(1)(E), (f)(1)(H), (f)(1)(I), and (f)(1)(J))
The 12-month rolling average trigger is proposed to be updated from $15,000 to $22,500 per ton for discrete credits. A trigger level of $35,000 per ton, also for discrete credits, has been added for a 3-month rolling average. If RTC prices exceed either of these levels, a report to the Board and a program review are required. Also included is a 12-month rolling average for Infinite Year Block (IYB) RTCs of $200,000 per ton. If credit prices are lower than this amount, then a report to the Board is also required.

The abovementioned report would include a commitment and schedule to conduct a more rigorous cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program.

Regional NSR Holding Account (Rule 2002 - subparagraphs (f)(1)(F), (f)(1)(G), (f)(1)(K) and Table 9; Rule 2005 - subparagraph (b)(2)(A) and paragraphs (f)(2) and (f)(3))
A Regional NSR Holding Account, held by the SCAQMD, would be used for the purpose of helping newer electricity generating facilities comply with the NSR requirements specified in Rule 2005 – New Source Review Requirements for RECLAIM.

State of Emergency Related to Electricity Generating Facilities (Rule 2002 - paragraphs (f)(4) and (f)(5))
These provisions address the activation of Non-tradable/Non-usable RTCs and the Regional NSR Holding Account during a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries. Also in these rule provisions are the procedures to determine the amount and distribution of the RTCs to the requesting EGFs.

RTC Reduction Exemption (Rule 2002 - subdivision (i))
Given that no facilities have applied for an exemption pursuant to subdivision (i) staff is proposing to remove the subdivision in its entirety.

Facility and Equipment Shutdowns (Rule 2002 - subdivision (i))
The proposed rule amendment includes a provision to address the retirement of RTCs from complete facility closure or equipment shutdowns that represent twenty-five percent or more of a facility's emissions for any quarter within the previous 2 compliance years. This would apply to any facility listed in Table 7 or 8 of Rule 2002. Permits associated with the equipment being shut down would be surrendered, and the RTCs for future years would be retired from the RECLAIM program.

Other Proposed Administrative Amendments

- 5-Year Limitation on Amending Annual Emission Reports (Rule 2002(b)(5))
- New procedures and criteria for postponing the due date of semi-annual or annual assessments (Appendix A to Rules 2011 and 2012)
- Various clarifications and minor edits

ATTACHMENT B

KEY ISSUES

Issue	Industry Comment	Staff Response
Amount of RTC Reductions	The 14 tpd emissions reduction as proposed by staff goes beyond the BARCT analysis. The 8.77 tpd is the BARCT adjustment. The additional 5.23 tpd goes beyond BARCT.	SCAQMD staff have significant concerns that proposals with less than 14 tons per day (TPD) would not meet the state law requirements for BARCT and command and control equivalency. The regulated community propose that the 8.77 tpd is the BARCT adjustment and that the additional 5.23 tpd goes beyond BARCT. On the other hand, the environmental community feel that all NOx reductions are needed to attain the ambient air quality standards. Therefore, the total reductions should be 14.8 tpd, including the 0.8 tpd that covers the potential uncertainties in the BARCT analysis. With regards the regulated community's proposal, staffs response has been that in order to achieve command and control equivalency there must be 10.21 tpd remaining emissions in 2023. This equates to a shave of 14 tpd which is the amount needed to achieve BARCT. It does not go beyond BARCT.
Timing of the RTC reductions	The initial RTC reduction of 4 tpd in 2016 is excessive. The timing of the RTC reductions should be back loaded in the later years.	Staff's response to this comment is that there are enough excess RTCs in the RECLAIM program to reduce the 4 tpd by 2016 without installing control equipment. Actual NOx reductions by control equipment would not be needed until 2018.

Issue	Industry Comment	Staff Response
		A uniform reduction from that point on will help avoid the concentration of materials, contractors and other resources at the end shave.
Equipment Life	The regulated community have raised concerns that the use of the discounted cash flow (DCF) method and 25-year useful life overstates cost effectiveness of controls. They feel that ten years is more appropriate	Staff provides both DCF and levelized cash flow (LCF) cost effectiveness estimates. Refineries have acknowledged that equipment lasts 25 years. The lifespan is consistent with other agencies and EPA assessments. A 10 year life assumes only if a rule is amended in 10 years that and investments are stranded assets. This is not a reasonable assumption. Staff is using the same cost effective threshold of \$50,000/ton that was approved for SOx RECLAIM. Moreover, the current NOx cost-effectiveness value has not been adjusted for inflation over the last 7 years. The average incremental cost effective for this proposed amendment is: • Refinery Sector: \$10,000/ton - \$17,000/ton • Non-Refinery Sector: \$9,000/ton - \$14,000/ton
The Gap Between Allocations and Actual Emissions	The regulated industry have commented that the gap between allocations and actual emissions should be much larger than what is being proposed. They feel that	The staff proposal includes a 10% compliance margin, adjustments, and growth projections for existing and new businesses. The resulting 23%

Issue	Industry Comment	Staff Response
	this gap is important for market function, including compliance margin, growth, investor holdings, and RTCs for new facilities and structural buyers.	gap is sufficient and consistent with past gaps in a functioning market.
Future Electricity Demands	The electricity generating facilities (EGF) have commented that there will be a significant adverse impact on achieving compliance with the NOx emissions due to future increased in electrical demand.	In response to this concern a Board Resolution language has been introduced to require staff to follow-up on the extent and impact that future power demands may be have on the EGFs. This language directs staff to monitor trends in NOx emissions from EGFs that could be attributable to increasing reliance on renewable sources of energy or increasing market penetration of electric vehicles. On or before April 30, 2017, and on an annual basis thereafter, staff will meet with a working group that includes representatives from the electricity generating industry to discuss and quantify any potential increases in NOx emissions resulting from these market trends. On or before June 30, 2017, and on an annual basis thereafter, staff will report to the Stationary Source Committee regarding any NOx emission increases from these facilities attributable to increased renewable energy or electric vehicle utilization, relative to the basin-wide NOx and greenhouse gas reduction benefits from technologies.

Issue	Industry Comment	Staff Response
		If staff finds that increased power supply intermittency and/or power demand are leading to increased NOx emissions from EGFs, but that these NOx emission increases are outweighed by the NOx and GHG reduction benefits of renewable energy and electrified mobile sources, then no later than 60 days after making that determination staff will make recommendations to the Stationary Source Committee on proposed program amendments designed to assist the affected EGFs with complying with their NOx RECLAIM obligations
EGF Opt-out of RECLAIM	Industry representatives outside of the EGFs have questioned why EGFs would be the industrial sector allowed to opt-out of RECLAIM.	For the following reasons staff feels EGFs should be the industrial sector to be allowed to opt-out of RECLAIM: • Electrical grid system has changed over time • EGFs are unique • Once-Through Cooling Regulation – older units repowered with cleaner, more efficient units • EGFs highly regulated • Most units already at BARCT or BACT • Provide essential public service • Other essential public services exempt from RECLAIM • Need to hold extra RTCs for NSR and/or to meet resource adequacy

Issue	Industry Comment	Staff Response
Retirement of RTCs from facility and equipment shutdowns	The regulated community have questioned why RTCs should be retired from facilities that have permanently shut down their equipment. They feel that these RTCs should remain in the RECLAIM program in order to maintain market stability.	Staff's response is that under command and control shutdown credits are discounted to BACT and based on last 2 years of operation. Currently, under a RECLAIM facility shutdown there is no discount of credits. In addition, these credits, if not removed from the program, reduce the incentive to implement cost-effective controls that would be required under command and control.
Potential dismantling of cap and trade underpinnings of RECLAIM	The Los Angeles County Business Federation (BizFed) has commented (on November 18, 2015) that the November 4, 2015 proposed rule language of (1) allowing EGFs to opt-out RECLAIM, and (2) requiring the retirement of RTCs from the facility and equipment permanently shut down would constitute a significant step towards dismantling the cap and trade structure of RECLAIM. As such they requested additional Working Group meetings to discuss the impacts of the proposed rule language and its impact on the face of RECLAIM.	Staff has responded by conducting two Working Group meetings (November 24 and 30, 2015) focused on the recent proposed rule language amendments. Staff does not believe the amendments in any way dismantle the market-based structure of the RECLAIM program. If all identified cost-effective controls are implemented, there will still be sufficient surplus RTCs to allow the market to function as it has in the past. Allowing the EGFs to opt-out, as stated above, is in recognition of their unique circumstances and their limited ability to implement additional controls. The retirement of RTCs upon permanent facility or equipment shutdown is necessary to maintain equivalency with command and control regulations.

Issue	Environmental Community Comment	Staff Response
Amount of RTC Reductions	The environmental groups feel that all NOx reductions are needed to attain the ambient air quality standards. Therefore, the total reductions should be 14.8 tpd, including the 0.8 tpd that covers the potential uncertainties in the BARCT analysis.	In considering NOx emission reductions while maintaining the stability of a functioning market, staff feels that a 0.8 tpd adjustment to account for uncertainty in the BARCT analysis is appropriate. Specifically, this 0.8 tpd is intended to cover the differences in engineering assumptions between staff and the consultant that reviewed staff's analysis, and other uncertainties that arose during the BARCT analysis

ATTACHMENT C

RULE DEVELOPMENT PROCESS

Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Initial Rule Development
October 2012

↓

- Fourteen Working Group Meetings: January 31, 2013, March 20, 2013, June 13, 2013, September 19, 2013, January 22, 2014, March 18, 2014, July 31, 2014, January 7, 2015, April 29, 2015, June 4, 2015, July 9, 2015, September 23, 2015, November 24, 2015, and November 30, 2015
- CEQA and Socioeconomic Scoping Meeting – January 8, 2015
- Public Workshop: July 22, 2015
- Public Consultation Meeting: September 29, 2015
- Stationary Source Committee Meetings: March 21, 2014, July 24, 2015, October 16, 2015, November 20, 2015, and a Special Stationary Source Committee on September 23, 2015

There were also numerous meetings with various stakeholders during the entire rulemaking process.

↓

Consultants hired to conduct independent BARCT analyses for the refinery and non-refinery sectors
September 2014 – December 2014

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CEQA Draft PEA Released for 53-Day Review
Release Date: August 14, 2015

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Set Public Hearing: October 2, 2015

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Public Hearing: December 4, 2015

Thirty-seven (37) months spent in rule development.

ATTACHMENT D
KEY CONTACTS LIST

Organizations
California Council for Environmental and Economic Balance (CCEEB)
Earth Justice
Industry Coalition
Regulatory Flexibility Group (RegFlex)
Southern California Air Quality Alliance (SCAQA)
Western States Petroleum Association

Facilities
Air Products
California Portland Cement Company
Chevron
ExxonMobil
Owens Brockway
Paramount
Phillips66
Tesoro
Ultramar
Other facilities

Manufacturers of Control Devices & Consultants
BASF
BELCO
Cheng Low NOx
ClearSign
Cormetech
ETS
Elex CEMCAT
Grace Davidson
Great Southern Flameless
Haldor Topsoe
INTERCAT
MECS
Mitsubishi
NEC
Tri-Mer

Others
California Air Resources Board
Bay Area Air Quality Management District
Santa Barbara Air Pollution Control District
San Joaquin Valley Air Pollution Control District
U.S. Environmental Protection Agency

ATTACHMENT E

RESOLUTION NO. 2015-____

A Resolution of the Governing Board of the South Coast Air Quality Management District (SCAQMD) certifying the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM).

A Resolution of the SCAQMD Governing Board amending Regulation XX – Regional Clean Air Incentives Market (RECLAIM).

WHEREAS, the 2012 AQMP was adopted by the SCAQMD Governing Board on December 7, 2012 and subsequently approved by the California Air Resources Board and submitted to the U.S. Environmental Protection Agency for inclusion into the State Implementation Plan; and

WHEREAS, the 2012 AQMP contained a control measure, CMB-01, that proposed to decrease NOx RECLAIM allocations and to reflect Best Available Retrofit Control Technology (BARCT) as required by state law; and

WHEREAS, the SCAQMD Governing Board has determined with certainty that the Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), is considered a "project" pursuant to the California Environmental Quality Act (CEQA); and

WHEREAS, the SCAQMD has had its regulatory program certified pursuant to Public Resources Code §21080.5 and has conducted a CEQA review pursuant to such program (SCAQMD Rule 110); and

WHEREAS, SCAQMD staff has prepared a Draft Program Environmental Assessment (PEA) pursuant to its certified regulatory program and CEQA Guidelines §15252 and §15168, setting forth the potential environmental consequences of Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM); and

WHEREAS, the Draft PEA was circulated for a 53-day public review period from August 14, 2015 to October 6, 2015; and

WHEREAS, the Draft PEA has been revised to include the comments received on the Draft PEA and the responses, such that it is now a Final PEA; and,

WHEREAS, it is necessary that the adequacy of the Final PEA, including responses to comments, be determined by the SCAQMD Governing Board prior to its certification; and

WHEREAS, the SCAQMD Governing Board finds and determines, taking into consideration the factors in Section (d)(4)(D) of the Governing Board Procedures, that the modifications which have been made to Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), since notice of public hearing was published do not significantly change the meaning of the proposed amended regulation within the meaning of the Health and Safety Code §40726 and would not constitute significant new information requiring recirculation of the Draft PEA pursuant to CEQA Guidelines §15073.5 and §15088.5; and,

WHEREAS, it is necessary that the SCAQMD prepare Findings and a Statement of Overriding Considerations pursuant to CEQA Guidelines §15091 and §15093, respectively, regarding potentially significant adverse environmental impacts that cannot be mitigated to insignificance; and a Mitigation Monitoring Plan pursuant to Public Resources Code §21081.6, regarding the mitigation included in the Final PEA; and

WHEREAS, the SCAQMD Governing Board has determined that the Socioeconomic Report for Regulation XX (RECLAIM), as proposed to be amended, is consistent with the March 17, 1989 and October 14, 1994 Board Socioeconomic Resolution for rule adoption; and

WHEREAS, the SCAQMD Governing Board has determined that the Socioeconomic Report for Regulation XX complies with Health and Safety Code §40440.8 (a) and (b), §40440.5, and §40728.5; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Amended Regulation XX may result in increased costs to industry, yet is considered to be appropriate, with total annualized costs as specified in the Final Socioeconomic Impact Assessment; and

WHEREAS, the SCAQMD Governing Board has actively considered the Socioeconomic Impact Assessment and has made a good faith effort to minimize such impacts; and

WHEREAS, the SCAQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from §§ 39002, 39650 et. seq., 40000, 40001, 40440, 40441, 40702, 40725 through 40728, 41508, 41700, and 44390 through 44394 of the Health and Safety Code; and

WHEREAS, Health and Safety Code §40727 requires that prior to adopting, amending or repealing a rule or regulation, the SCAQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and

WHEREAS, the SCAQMD Governing Board has determined that a need exists to amend Regulation XX to implement the 2012 AQMP and BARCT as required by state law; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Amended Regulation XX is written or displayed so that the meaning can be easily understood by the persons directly affected by it; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Amended Regulation XX is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Amended Regulation XX will not impose the same requirements as any existing state or federal regulations. The amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, AQMD; and

WHEREAS, the SCAQMD Governing Board has determined that by adopting Proposed Amended Regulation XX, the SCAQMD Governing Board will be implementing, interpreting and making specific the provisions of the Health and Safety Code §§ 39002, 40000, 40001, 40440 (a), 40440.1, 40702, and 40725 through 40728.5; and Title 42 U.S.C. §§ 7410 and 7511a; and

WHEREAS, the SCAQMD Governing Board has determined that there is a problem, that the proposed amendments to Regulation XX will alleviate (Health and Safety Code § 40001(c)). Specifically, RECLAIM facility NOx emissions do not currently reflect BARCT levels, as required by section 40440, and these proposed amendments will reduce NOx credits in the RECLAIM market so as to reflect BARCT; and

WHEREAS, the Governing Board finds that Health and Safety Code section 39616 does not apply to the proposed amendments to RECLAIM. The Governing Board further finds that in the absence of the 39616 findings being made, the Board could and would nonetheless adopt these proposed amendments. Nonetheless, the SCAQMD Governing Board makes the following findings when considering the NOx RECLAIM program on an aggregate basis, that:

> pursuant to Health and Safety Code §39616(c)(l), the proposed amendments to RECLAIM achieve the emissions levels projected to result from implementation of the rules and control measures subsumed by RECLAIM and current BARCT at equal or less cost, as set forth and explained in the Socioeconomic Report; and
>
> pursuant to Health and Safety Code §39616(c)(2), the proposed amendments to RECLAIM do not change the previous findings that RECLAIM provides a level of

enforcement and monitoring comparable to or more stringent than command and control air quality measures by requiring more frequent and more accurate monitoring, more frequent and more complete emissions reports, electronic emissions reporting, maintenance of on-site records of emissions reports and underlying data for three years, annual or more frequent facility inspections, and annual emissions audits; and

pursuant to Health and Safety Code §39616(c)(4), the proposed amendment to RECLAIM will not result in a greater loss of jobs or more significant shifts from higher to lower skilled jobs, on an overall District-wide basis, than would exist under command and control air quality measures, as set forth and explained in the Socioeconomic Report; and

pursuant to Health and Safety Code §39616(c)(5), the proposed amendments to RECLAIM do not affect the findings previously made by the Governing Board with respect to this subdivision; and

pursuant to Health and Safety Code §39616(c)(6), the proposed amendments to RECLAIM will not in any manner delay, postpone, or otherwise hinder District compliance with District plans to attain state Ambient Air Quality Standards because the amendments implement BARCT as required by Health and Safety Code §40919(a)(3) ; and

pursuant to Health and Safety Code §39616(c)(7), the proposed amendment to RECLAIM will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the SCAQMD's plan for attainment because the sources included in the amendments are subject to BARCT requirements ; and

WHEREAS, the SCAQMD specifies the Director of Regulation XX as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of these proposed amendments is based, which are located at the South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, California; and

WHEREAS, the SCAQMD Governing Board has determined that proposed amendments to Regulation XX should be adopted for the reasons contained in the staff report, including compliance with BARCT; and

WHEREAS, the SCAQMD Governing Board finds that pursuant to Health and Safety Code section 40920.6(a)(5) the reason that it is adopting the proposed amendments to RECLAIM is because the amendments will achieve BARCT level emissions from NOx RECLAIM sources in an equitable manner.

WHEREAS, a public hearing has been properly noticed in accordance with the provisions of Health and Safety Code § 40725; and

WHEREAS, the SCAQMD Governing Board has held a public hearing in accordance with all provisions of law; and

WHEREAS, the SCAQMD Governing Board prior to voting on Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), has reviewed, considered, and approved the Final PEA, including responses to comments, prior to its certification.

NOW, THEREFORE, BE IT RESOLVED, that the SCAQMD Governing Board does hereby certify the Final PEA for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) was completed in compliance with CEQA and SCAQMD Rule 110 provisions; and finds that the Final PEA was presented to the Governing Board, whose members reviewed, considered and approved the information therein prior to acting on Proposed Amended Regulation XX; and

BE IT FURTHER RESOLVED, that the Governing Board adopts Findings and a Statement of Overriding Considerations pursuant to CEQA Guidelines §15091 and §15093, respectively, and a Mitigation Monitoring Plan pursuant to Public Resources Code §21081.6 regarding potentially significant adverse environmental impacts that cannot be mitigated to insignificance, as required by CEQA, and which are included as Attachment 1 and incorporated herein by reference; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby approve the Socioeconomic Report; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby amend, pursuant to the authority granted by law, Regulation XX, as set forth in the attached, and incorporated herein by reference; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby direct staff to submit into the State Implementation Plan a commitment of 14 tons per day by the year 2022, less the total amount in the Regional NSR Holding Account, to further ensure that the reduction commitments comply with state law; and

BE IT FURTHER RESOLVED, that the Governing Board hereby directs the Executive Officer to submit the NOx emission reductions associated with the Non-tradable/Non-usable RTCs for a compliance year minus the amount listed in Table 9 for the same compliance year at the conclusion of that compliance year provided that NOx RTC process have not exceeded the $22,500 price threshold and provided that the Governor has not declared a State of Emergency related to electricity demand of power grid stability within the SCAQMD jurisdictional boundaries, consistent with Rule 2002(f)(1)(K); and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby direct staff to re-evaluate programmatic BARCT and command and control equivalency as part of future AQMP revisions, and propose AQMP control measures to further reduce emissions as necessary in accordance with such evaluation; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board hereby directs the Executive Officer to submit Regulation XX, as currently amended, with the exception of the RECLAIM Trading Credits in the Regional New Source Review Holding Account as listed in Table of Rule 2002, for inclusion into the California State Implementation Plan.

BE IT FURTHER RESOLVED, that the Governing Board does hereby direct staff to monitor trends in NOx emissions from electricity generating facilities that could be attributable to increasing reliance on renewable sources of energy or increasing market penetration of electric vehicles. The Governing Board further directs that on or before April 30, 2017, and on an annual basis thereafter, staff shall meet with a working group that includes representatives from the electricity generating industry to discuss and quantify any potential increases in NOx emissions resulting from these trends. On or before June 30, 2017, and on an annual basis thereafter, staff shall report to the Stationary Source Committee regarding any NOx emission increases from these facilities attributable to increased renewable energy or electric vehicle utilization, relative to the basin-wide NOx and GHG reduction benefits. The Governing Board further directs that if staff finds that increased power supply intermittency and/or power demand are leading to increased NOx emissions from electricity generating facilities, but that these NOx emission increases are outweighed by the NOx and GHG reduction benefits of renewable energy and electrified mobile sources, then no later than 60 days after making that determination staff will make recommendations to the Stationary Source Committee on proposed program amendments designed to assist the affected electrical generating facilities with complying with their NOx RECLAIM obligations.

DATE: _______________ _______________________________

CLERK OF THE BOARDS

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Attachment 1 to the Governing Board Resolution for:
Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan

SCAQMD No. 12052014BAR
State Clearinghouse No: 2014121018

November 2015

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ATTACHMENT 1 TO THE GOVERNING BOARD RESOLUTION FOR: FINAL PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

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INTRODUCTION

The proposed amendments to Regulation XX - Regional Clean Air Incentives Market (RECLAIM) are considered a "project" as defined by the California Environmental Quality Act (CEQA) (California Public Resources Code §§21000 et seq.). The SCAQMD as Lead Agency for the proposed project, prepared a Notice of Preparation/Initial Study (NOP/IS) which identified environmental topics to be analyzed in a Draft Program Environmental Assessment (PEA). The NOP/IS provided information about the proposed project to other public agencies and interested parties prior to the intended release of the Draft PEA. The NOP/IS was distributed to responsible agencies and interested parties for a 57-day public review and comment period from December 5, 2014 to January 30, 2015. The initial evaluation in the NOP/IS identified the topics of aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic, as potentially being significantly adversely affected by the project. Since the proposed project may have statewide, regional or areawide significance, a CEQA scoping meeting is required and was held for the proposed project pursuant to Public Resources Code §21083.9 (a)(2) on January 8, 2015. Eight comment letters were received from the public regarding the preliminary analysis in the NOP/IS. None of these comment letters identified other potentially significant adverse impacts from the proposed project that should be analyzed in the PEA.

The Draft PEA was released for a 53-day public review and comment period from August 14, 2015 to October 6, 2015 and further analyzed whether or not the potential adverse impacts to the environmental topic areas identified in the NOP/IS are significant. The Draft PEA concluded that only the topics of air quality and greenhouse gases (GHGs), hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) would have significant adverse impacts. The Draft PEA included the NOP/IS (in Appendix F), the comment letters received relative to the NOP/IS and responses to individual comments (in Appendix G), and a summary of comments made at the CEQA scoping meeting and responses to individual comments (in Appendix H).

Eight comment letters were received during the public comment period on the analysis presented in the Draft PEA. Responses to these comment letters have been prepared and are included in Appendix I of the Final PEA The Final PEA, prepared pursuant to CEQA Guidelines §15132, identifies air quality and GHGs, hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) as areas that may be adversely affected by the proposed project.

In addition to incorporating the comment letters and the responses to comments, some modifications have been made to the Draft PEA to make it a Final PEA. SCAQMD staff evaluated these modifications and concluded that none of the modifications alter any conclusions reached in the Draft PEA, nor do they constitute significant new information[1] and, therefore, do not require recirculation of the document pursuant to CEQA Guidelines §§15073.5 and 15088.5. The Final PEA will be presented to the Governing Board prior to its December 4, 2015 public hearing.

SUMMARY OF THE PROPOSED PROJECT

To comply with the requirements in Health and Safety Code §40440 by conducting a Best Available Retrofit Control Technology (BARCT) assessment, SCAQMD staff is proposing amendments to the following rules which are part of Regulation XX – Regional Clean Air Incentives Market (RECLAIM): Rule 2001 – Applicability; Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx); Rule 2005 – New Source Review For RECLAIM; Attachment C from Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions; and, Attachment C from Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions. The proposed amendments to Regulation XX would reduce emissions from equipment and processes operated at NOx RECLAIM facilities located throughout the entire SCAQMD jurisdiction. In particular, the environment could be impacted from the proposed project due to facilities installing new, or modifying existing control equipment for the following types of equipment/source categories in the NOx RECLAIM program: 1) fluid catalytic cracking units; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. For clarity and consistency throughout the regulation, other minor revisions are also proposed.

The proposed project is expected to result in a total of 14 tons per day (tpd) of reduction of NOx RECLAIM Trading Credits (RTCs) from the current 2015 RTC holdings of 26.5 tpd over a seven-year period from 2016 to 2022. The 14 tpd of NOx RTC reductions will be reduced from the allocations of 56 facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 219 facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC

[1] Pursuant to CEQA Guidelines §§ 15073.5 and 15088.5, circumstances that would require recirculation include, for example, any of the following:

(1) A new, avoidable significant effect would result from the project or from a new mitigation measure proposed to be implemented, or new mitigation measures or project revisions must be added in order to reduce the effect to insignificance.
(2) The proposed mitigation measures or project revisions will not reduce the effects to less than significance and new measures or revisions are required.
(3) A substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance.
(4) A feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it.
(5) The draft CEQA document was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded.

shave is proposed because either no new BARCT (not cost effective and/or infeasible) was identified, or gains in emission reductions would be negligible, for the types of equipment and source categories at these facilities. By following this approach, the shave is distributed as follows:

- 66% shave for 9 refineries and investors (treated as one facility)
- 49% shave for 21 electricity generating facilities (EGFs)
- 49% shave for 26 non-major facilities
- 0% shave for 219 remaining facilities

In addition, the overall NOx RTC reductions of 14 tpd are expected to be achieved incrementally from 2016 to 2022, according to the following implementation schedule:

- 2016 – 4 tons per day
- 2018 – 2 tons per day
- 2019 – 2 tons per day
- 2020 – 2 tons per day
- 2021 – 2 tons per day
- 2022 – 2 tons per day

POTENTIAL SIGNIFICANT ADVERSE IMPACTS THAT CANNOT BE REDUCED BELOW A SIGNIFICANT LEVEL

The Final PEA identified the topics of air quality (during construction) and GHGs (from combined construction and operation activities), hydrology (due to water demand), and, hazards and hazardous materials (due to ammonia transportation) as the only areas that may be significantly adversely affected by the proposed project. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one fluid catalytic cracking unit (FCCU) in 2017. Thus, the projected installation of wet gas scrubber (WGS) technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of selective catalytic reduction (SCR) units that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potentially significant adverse impacts that cannot be reduced below a significant level for the following environmental topics.

Air Quality Impacts During Construction

Relative to construction emissions, the "worst-case" scenario is when construction activities overlap due to concurrent construction activities occurring at a single facility and at multiple facilities. Specifically, the scenario analyzed in the Final PEA is the simultaneous activities of demolishing existing equipment, site preparation, and constructing new or modifying existing air pollution control equipment, which could occur at a single facility or at more than one facility. The analysis further assumes that the "worst-case" day is that in which each construction project is operating construction equipment that generates the greatest emissions.

Based on these assumptions for overlapping construction activities, the "worst-case" emissions were calculated to be: 429 pounds per day of volatile organic compounds (VOC); 1,656 pounds per day of NOx; 2,745 pounds per day of carbon monoxide (CO); 3 pounds per day of oxides of sulfur (SOx); 1,758 pounds per day before mitigation and 853 pounds per day after mitigation of particulate matter with an aerodynamic diameter less than 10 microns (PM10), respectively; and, 883 pounds per day before mitigation and 430 pounds per day after mitigation of particulate matter with an aerodynamic diameter less than 2.5 microns (PM2.5), respectively. The significance thresholds for construction-related emissions are: 75 pounds per day of VOC; 100 pounds per day of NOx; 550 pounds per day of CO; 150 pounds per day of SOx; 150 pounds per day of PM10; and 55 pounds per day of PM2.5. (Estimated construction emissions did not exceed the significance threshold for SOx.) Because the construction emissions for all of the pollutants except SOx exceed the applicable significance thresholds for construction, mitigation measures are required.

While the air quality mitigation measures for construction that are identified in the Mitigation Monitoring Plan section of this document may reduce construction emissions to the maximum extent feasible, none are mitigation measures that will avoid the significant impacts or reduce the construction air quality impacts to less than significant. Also, no other feasible mitigation measures have been identified to reduce construction air quality emissions to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative air quality impacts during construction.

Greenhouse Gas Impacts

With regard to GHG emissions, the proposed project involves combustion processes during both construction and operation, which could generate GHG emissions such as carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O). However, the proposed project does not affect equipment or operations that have the potential to emit non-combustion GHGs such as sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs).

Installation of new or modification of existing NOx control equipment as part of implementing the proposed project is expected to generate construction-related CO2 emissions. In addition, based on the type and size of equipment affected by the proposed project, CO2 emissions from the operation of the NOx control equipment are likely to increase from current levels due to electricity, fuel and water use. The proposed project will also result in an increase of GHG operational emissions produced from additional truck hauling and deliveries necessary to accommodate the additional solid waste generation and increased use of supplies and chemicals such as catalyst and caustic.

For the purposes of addressing the GHG impacts of the proposed project, the overall impacts of CO2 equivalent (CO2e) emissions from the project were estimated and evaluated from the earliest possible initial implementation of the proposed project with construction beginning in 2016. Once the proposed project is fully implemented, the potential NOx emission reductions would continue through the end of the useful life of the equipment. The analysis estimated CO2e emissions from all sources subject to the proposed project (construction and operation) from the beginning of the proposed project (2016) to the end of construction (2022). The beginning of the proposed project was assumed to be no sooner than 2016, since installing NOx control equipment requires planning and engineering in advance. Full implementation of the proposed project is expected to occur by the end of 2022 when the entire 14 tons per day of the NOx RTC shave is completed such that any installed or modified NOx controls could be constructed and operational by this final date. Thus, once construction is complete and the equipment is operational, CO2e emissions will continue to be generated but they will remain constant.

Implementing the proposed project is expected to increase GHG emissions that exceed the SCAQMD's GHG significance threshold for all 11 of the non-refinery facilities and nine refinery facilities, should these facility operators choose to install NOx control technology in response to the proposed project. This potentially significant adverse impact cannot be mitigated below significance. The SCAQMD's GHG significance threshold for industrial sources is 10,000 metric tons of CO2e emissions per year (MTCO2e/yr). While none of the affected facilities individually exceed the GHG industrial significance threshold of 10,000 MTCO2e/yr, the "worst-case" GHG emissions from the proposed project as a whole were calculated to be 41,785 MTCO2e/yr which exceeds the SCAQMD's GHG significance threshold. Thus, the overall GHG emissions exceed the GHG significance threshold and therefore, the proposed project is considered to have significant adverse GHG impacts.

Recycled water projects and the utilization of recycled water are among the most direct ways to reduce GHG from combustion activities associated with conveying water to the affected facilities if water-intensive scrubbers are installed as a result of the proposed project. Specifically, the energy it would take to treat and convey reclaimed water to a facility (e.g., 1,200 kilowatt-hours per million gallons (kWh/MMgallons)[2]) is approximately 10 times less than the amount of energy it would take for potable water (e.g., 12,700 kWh/MMgallons[3]) to be supplied, conveyed and distributed. Thus, for each facility that has access to recycled water and chooses to use recycled water to satisfy the water demands for the proposed project and in turn, mitigate CO2e emissions, less GHG emissions would be generated for the operational water use/conveyance and operational wastewater generation portions of the proposed project. After mitigation, the GHG emissions from the proposed project as a whole were calculated to be 41,100 MTCO2e/yr which still exceeds the SCAQMD's GHG significance threshold.

While the GHG mitigation measures identified in the Mitigation Monitoring Plan section of this document may reduce GHG emissions associated with water conveyance to the maximum extent feasible, none are mitigation measures that will avoid the significant impact or reduce the GHG impact to less than significant. Also, no other feasible mitigation measures have been identified to reduce GHG emissions to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative GHG impacts.

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[2] California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

Water Demand Impacts

Post-Construction/Pre-Operation Activities: Implementation of the proposed project may cause potentially significant adverse water demand impacts associated with hydrotesting equipment post-construction/pre-operation. Specifically, once construction of control equipment and support equipment is completed, but prior to operation of the control equipment, additional water is expected to be used to hydrostatically (pressure) test all storage tanks and pipelines to ensure each structure's integrity. Pressure testing or hydrotesting is typically a one-time event, unless a leak is found.

The analysis in the Final PEA shows that the potential increase in water use for all 20 facilities conducting hydrotesting activities in one day is approximately 353,724 gallons per day which is greater than the SCAQMD's significance threshold of 262,820 gallons per day of potable water. Thus, the amount of potable water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is potentially significant. However, water used for pressure testing does not have to be of potable quality, but can be recycled water. Alternately, facility operators may substitute the use of purchased recycled water with non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility. In addition, water used during hydrotesting can be sent somewhere else within a facility for future re-use. Nonetheless, without being able to predict what type of water each facility will use for hydrotesting purposes, the "worst-case" analysis in the Final PEA assumes that 100 percent of potable water could be utilized for hydrotesting purposes and concludes that hydrotesting could cause significant adverse water demand impacts post-construction but prior to operation.

While the use of recycled water may reduce potable water demand during hydrotesting to the maximum extent feasible, the use of recycled water will not avoid the significant impact or reduce the potable water demand impact post-construction but prior to operation to less than significant. Therefore, the proposed project may cause significant potable water demand impacts during hydrotesting post-construction but prior to operation.

Thus, while the mitigation measures that are identified in the Mitigation Monitoring Plan section of this document may reduce potable water demand associated with hydrotesting activities to the maximum extent feasible, the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to either recycled water or other sources of non-potable water. While feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of limitations with access to recycled water or other sources of non-potable water. Thus, the proposed mitigation measures may not fully avoid the significant impact or reduce the potable water demand impact to less than significant. Also, no other feasible mitigation measures have been identified to reduce the potable water demand during hydrotesting to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative water demand impacts during hydrotesting.

Operation Activities: Implementation of the proposed project may cause potentially significant adverse water demand impacts associated with operating NOx control equipment. Specifically, of the technologies proposed as BARCT for NOx control, only WGSs utilize water. For this reason, only WGS technology was identified as having the potential to generate potentially significant adverse water demand impacts during operation and WGS technology would be BARCT for equipment at seven of the 20 facilities, and all seven of these facilities belong to the refinery sector (e.g., Refineries 1, 2, 4, 5, 6, 8 and 9).

The analysis in the Draft PEA shows that the potential increase in water use for seven facilities that may operate WGSs is approximately 602,814 gallons per day which is greater than the SCAQMD's significance threshold of 262,820 gallons per day of potable water. However, operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the installation of WGS technology along with the corresponding increased water demand and wastewater generation projections that were originally contemplated for one of the two FCCUs (e.g., Refineries 4 and 9) are no longer expected to occur. Thus, the potential increase in operational water demand is expected to be less than what was originally analyzed in the Draft PEA. To protect the identity of the refinery in this document, the revised potential increase in operational water demand has been presented as a range in the Final PEA, from 553,499 to 558,978 gallons per day, instead of 602,814 gallons per day.

Of the seven affected refineries, three (e.g., Refineries 1, 5, and 6) currently access recycled water from the Harbor Refineries Recycled Water Pipeline (HRRWP) which is maintained by the Los Angeles Department of Water and Power (LADWP), in conjunction with the West Basin Municipal Water District (WBMWD). The LADWP/WBMWD currently provides 35 million gallons per day (MMgal/day) of recycled water to its customers, which include Refineries 1, 5, and 6. The WBMWD is also in the process of expanding its Hyperion Pump Station to accommodate a throughput of 70 MMgal/day of source water which would result in about 55 to 60 MMgal/day of saleable recycled water if, and when needed to accommodate any increased need by their customers. Thus, should operators of these three refineries commit to utilizing recycled water in lieu of potable water to satisfy the water demand for the NOx control equipment, then the LADWP/WBMWD would be able to supply the additional water (e.g., 398,767 gallons per day or approximately 71 percent of the projected water demand). If these facilities do not utilize recycled water for the proposed project, SCAQMD staff conducted an analysis of potable water supply and concluded that potable water would be available to supply the projected increased water demand at Refineries 1, 5 and 6 (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, pp. 4.5-15 to 4.5-20).

Refineries 4, 8, and 9 are not currently connected to the HRRWP to access recycled water. However, Refinery 4 is in the process of finalizing an agreement with WBMWD to acquire 2,240 acre-feet/year (AF/yr)[4] of recycled water (equivalent to two MMgal/day) to replace its current potable water use with recycled water by 2018. In addition, Refineries 4, 8, and 9 are currently in talks with the LADWP and WBMWD to negotiate options for replacing as much as 11,100 AF/yr (equivalent to approximately 9.9 MMgal/day) of current potable water use with

[4] 1 acre-foot = 325,851 gallons

recycled water instead via the HRRWP[5]. Thus, if Refineries 4, 8 and 9 need additional recycled water in response to this proposed project, the LADWP/WBMWD has the capacity to provide additional recycled water as necessary. Again, if these facilities do not obtain access to recycled water for the proposed project, SCAQMD staff conducted an analysis of potable water supply and concluded that potable water would be available to supply the projected increased water demand at Refineries 4, 8 and 9 (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, pp. 4.5-15 to 4.5-20).

Refinery 2 is not located near the HRRWP nor any other recycled water pipeline so it is unlikely that Refinery 2 would be able to obtain recycled water should facility operators choose to install a WGS and instead, would need to satisfy the water demand with potable water. According to the LBWD's 2010 UWMP that was prepared in accordance with the California Water Code §10608.20, the potable water delivery projections to their industrial and commercial customers show a long-term projected increase in potable water supply with a slight tapering occurring in years 2030 and 2035 to reflect offsetting by increased deliveries of recycled water to other customers currently being supplied by LBWD with potable water. Based on LBWD's short- and long-term projections for potable water supplies, SCAQMD staff believes that the potential increased water demand of 40,896 gallons per day for Refinery 2 can be accommodated with potable water (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, p. 4.5-20).

In addition, it is important to keep in mind that operators of Refinery 2 have two different types of control equipment options available for consideration. As summarized in the PEA (see Tables 1-2 and 1-3 for the petroleum coke calciner source category), the BARCT NOx levels of 10 ppmv corrected for 3% oxygen can be achieved with either a WGS which uses water, or a DGS, which does not. While the analysis in this subchapter considers the technology with the worst-case impacts to water demand and water quality, for Refinery 2, installing WGS technology is not their only option. Should operators choose to install a DGS, instead of a WGS, then no water would be needed.

Thus, while the amount of water demand that would be needed to operate NOx control equipment would be 398,767 gallons per day at Refineries 1, 5 and 6 and the amount of water demand at Refineries 2, 4, 8, and 9 would be in the range of 113,836 gallons per day to 160,211 gallons per day, which collectively is greater than the significance threshold of 262,820 gallons per day of potable water but less than the significance threshold of five million gallons per day of total water (e.g., potable, recycled, and groundwater), in consideration that Refineries 1, 5 and 6 have a high potential to use recycled water because of their current access and in light of the negotiations for recycled water at Refineries 4, 8, and 9, potable water only may be needed for a future project occurring at Refinery 2, or not at all if operators of Refinery 2 choose to install a DGS instead of a WGS. In any case, the previous analysis shows that water purveyor would be able to supply potable water to Refinery 2 and to Refineries 1, 4, 5, 6, 8 and 9, if needed. Thus,

[5] City of Los Angeles, Inter-Departmental Correspondence to City Council From Los Angeles Department of Water and Power and Los Angeles Department of Public Works Bureau of Sanitation, Council File No. 15-0018 Harbor Refineries Pipeline Project/Advanced Water Purification Facility/Water Supply Efforts, April 10, 2015. https://cityclerk.lacity.org/lacityclerkconnect/index.cfm?fa=ccfi.viewrecord&cfnumber=15-0018

using an abundance of caution, because the peak daily water demand for the proposed project exceeds the potable water threshold of 262,820 gallons per day and because recycled water is not currently available at Refineries 4, 8 and 9, and no contractual commitments to increase recycled water demand above the existing recycled water baseline for the three refineries that already have access to recycled water (e.g., Refineries 1, 5 and 6) have been finalized, the analysis conservatively assumes that significant adverse impacts associated with water demand are expected from the proposed project during operation.

Thus, while the mitigation measures that are identified in the Mitigation Monitoring Plan section of this document may reduce potable water demand associated with operation activities to the maximum extent feasible, the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to recycled water. While feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of limitations with access to recycled water. Thus, the proposed mitigation measures may not fully avoid the significant impact or reduce the potable water demand impact to less than significant. Also, no other feasible mitigation measures have been identified to reduce the operational potable water demand to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative water demand impacts during operation.

Hazards and Hazardous Materials Impacts From Delivering Ammonia

The Final PEA assumes that some facilities may opt to reduce NOx emissions by installing NOx control equipment such as SCRs and DGSs which requires the use of ammonia, a chronic and acutely hazardous material. Further, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents). In particular, the analysis assumes that as many as 117 SCRs could be installed at 20 facilities and one Ultracat DGS could be installed at one facility. The analysis estimates that approximately 39.5 tons per day (equivalent to approximately 10,284 gallons per day) of aqueous ammonia (at 19 percent concentration) would be needed to operate the equipment. It is expected that the affected facilities will receive ammonia from a local ammonia supplier located in the greater Los Angeles area. Deliveries of aqueous ammonia would be made by tanker truck via public roads.

The accidental release of ammonia from a delivery is a localized event (i.e., the release of ammonia would only affect the receptors that are within the zone of the toxic endpoint). The accidental release from a delivery would also be temporally limited in the fact that deliveries are not likely to be made at the same time in the same area. Based on these limitations, the analysis in the Final PEA assumed that an accidental release would be limited to a single delivery or single facility at a time. In the ammonia transportation release scenario, the distance to the toxic endpoint from a worst-case delivery truck release was estimated to be 0.4 miles or 2,112 feet. Since sensitive receptors are expected to be found within 0.4 miles from roadways, the hazards and hazardous materials impacts due to a delivery truck accident were concluded to be potentially significant. Therefore, the proposed project was concluded to have significant adverse hazards and hazardous materials impacts due to ammonia deliveries and mitigation measures are required. However, no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia.

FINDINGS

Public Resources Code §21081 and CEQA Guidelines §15091 (a) state that no public agency shall approve or carry out a project for which a CEQA document has been completed which identifies one or more significant adverse environmental effects of the project unless the public agency makes one or more written findings for each of those significant effects, accompanied by a brief explanation of the rationale for each finding. Additionally, the findings must be supported by substantial evidence in the record (CEQA Guidelines §15091 (b)). As identified in the Final PEA and summarized above, the proposed project has the potential to create significant adverse impacts for the topics of air quality during construction, water demand, and hazardous materials due to deliveries of ammonia. The SCAQMD Governing Board, therefore, makes the following findings regarding the proposed project. The findings are supported by substantial evidence in the record as explained in each finding. The findings will be included in the record of project approval and will also be noted in the Notice of Decision. The findings made by the SCAQMD Governing Board are based on the following significant adverse impacts identified in the Final PEA.

1. **Potential project-specific and cumulative VOC, CO, NOx, PM10, and PM2.5 emissions during construction exceed the SCAQMD's applicable significance air quality thresholds and cannot be mitigated to insignificance.**

   Finding and Explanation:
   The implementation of the proposed project is anticipated to trigger construction activities associated with the installation of new or the modification of existing NOx air pollution control equipment. Construction activities associated with the proposed project would result in emissions of VOC, CO NOx, SOx, PM10, and PM2.5, but only the estimated emissions for SOx are expected to remain below the SCAQMD's applicable significance air quality thresholds for construction. As a result, the proposed project is expected to have significant adverse construction air quality impacts. However, the temporary construction emissions would cease upon completion of the installation of new or modification of existing air pollution control equipment, as applicable. Once all the modified or new equipment are in place, the proposed project is expected to result in a reduction of NOx emissions of 14 tons per day by 2023.

   The Governing Board finds that mitigation measures have been identified, but they would not reduce to insignificance the significant adverse project-specific or cumulative impacts to air quality associated with construction. No other feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

   The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant project-specific or cumulative construction air quality impacts that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

2. **Potential GHG emissions exceed the SCAQMD's applicable significance GHG threshold and cannot be mitigated to insignificance.**

Finding and Explanation:
While none of the affected facilities individually exceed the SCAQMD's industrial GHG significance threshold of 10,000 MTCO2e/yr, if the proposed project is implemented, the analysis indicates that there would be a significant increase in GHG emissions for the project as a whole. Because there are significant adverse GHG impacts from the proposed project, the PEA must describe feasible measures that could minimize significant adverse impacts.

The Governing Board finds that mitigation measures have been identified, but they would not reduce to insignificance the significant adverse GHG emission impacts. No other feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant GHG impacts that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

3. **Potential potable water demand would use a substantial amount of potable water and cannot be mitigated to insignificance.**

Finding and Explanation:
The Final PEA concluded that the proposed project may cause significant adverse potable water demand impacts during hydrotesting post-construction but prior to operation and during operation of NOx control equipment. Because there are significant adverse potable water demand impacts from the proposed project, the Final PEA must describe feasible measures that could minimize significant adverse impacts. Mitigation measures have been identified that may be effective in reducing the amount of potable water needed, however, they may not completely avoid or reduce the adverse potable water demand impact to a less than significant level.

The Governing Board finds that mitigation measures have been identified, but they would not reduce to insignificance the significant adverse water demand impacts. No other feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant water demand impacts that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

4. **Potential hazards and hazardous materials impacts due to deliveries of ammonia may significantly increase the current existing risk setting associated with truck and road accidents and cannot be mitigated to insignificance.**

<u>Finding and Explanation</u>:
The Final PEA concluded that the proposed project may cause significant adverse hazards and hazardous materials impacts during deliveries of ammonia to facilities that may install NOx emissions control equipment that require the use of ammonia. Because there are significant adverse hazards and hazardous materials impacts from the proposed project, the Final PEA must describe feasible measures that could minimize significant adverse impacts. However, no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia, that could minimize or reduce the significant hazards and hazardous materials impacts due to deliveries of ammonia.

The Governing Board finds that no feasible mitigation measures have been identified that would reduce to insignificance the significant adverse hazards and hazardous materials impacts due to deliveries of ammonia. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant hazards and hazardous materials impacts due to deliveries of ammonia that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

Conclusion of Findings

The Governing Board finds that feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to the following topics: air quality during construction, GHG emissions, and water demand. The Governing Board also finds that no feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to hazards and hazardous materials due to deliveries of ammonia. CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors" (Public Resources Code §21061.1).

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant impacts to the topics of air quality during construction, GHG emissions, water demand, and hazards and hazardous materials due to deliveries of ammonia that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

The Governing Board further finds that a Mitigation Monitoring Plan (pursuant to Public Resources Code §21081.6) needs to be prepared since feasible mitigation measures were identified for the topics of air quality during construction, GHG emissions, and water demand.

The Governing Board further finds that the findings required by CEQA Guidelines §15091 (a) are supported by substantial evidence in the record. Further, to comply with CEQA Guidelines §15091 (e), the SCAQMD specifies the director of Regulation XX as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of these proposed amendments and the approval of this project is based, and which are located at the SCAQMD headquarters, 21865 Copley Drive, Diamond Bar, California 91765.

STATEMENT OF OVERRIDING CONSIDERATIONS

If significant adverse impacts of a proposed project remain after incorporating mitigation measures, or no measures or alternatives to mitigate the adverse impacts are identified, the lead agency must make a determination that the benefits of the project outweigh the unavoidable adverse environmental effects if it is to approve the project. CEQA requires the decision-making agency to balance, as applicable, the economic, legal, social, technological, or other benefits of a proposed project against its unavoidable environmental risks when determining whether to approve the project [CEQA Guidelines §15093 (a)]. If the specific economic, legal, social, technological, or other benefits of a proposed project outweigh the unavoidable adverse environmental effects, the adverse environmental effects may be considered “acceptable” [CEQA Guidelines §15093 (a)]. Accordingly, a Statement of Overriding Considerations regarding potentially significant adverse impacts to air quality during construction, GHGs, water demand, and hazardous materials due to deliveries of ammonia that may result from the proposed project has been prepared. This Statement of Overriding Considerations is included as part of the record of the project approval for the proposed project. Pursuant to CEQA Guidelines

§15093 (c), the Statement of Overriding Considerations will also be noted in the Notice of Decision for the proposed project.

Despite the inability to incorporate changes into the proposed project that will mitigate potentially significant adverse impacts to a level of insignificance for the topics of air quality during construction, GHG emissions, water demand, and, hazards and hazardous materials due to deliveries of ammonia, the SCAQMD's Governing Board finds that the following benefits and considerations outweigh the significant unavoidable adverse environmental impacts:

1. The analysis of potential adverse environmental impacts incorporates a “worst-case” approach. This entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method likely overestimates the actual environmental impacts from the proposed project.

2. Each of the alternatives was crafted to show the various possibilities or permutations of how operators of NOx RECLAIM facilities could achieve actual NOx reductions, but ultimately, there is no way to predict what each facility operator will do. Further, because of the compliance flexibility inherent in the RECLAIM program, affected operators may choose to reduce NOx emissions using compliance options that minimize or eliminate significant environmental impacts at their facilities.

3. The 2012 AQMP identifies ambient air pollutant levels relative to federal and state ambient air quality standards (AAQS), establishes baseline and future emissions, and develops control measures to ensure attainment of the AAQS. Construction is a continuous activity in the district and is accounted for in the AQMP. Thus, any changes in air quality as a result of construction emissions from the proposed project are accounted for in the AQMP and would not be expected to interfere with the attainment demonstrations.

4. The proposed project implements 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM (e.g., at least three to five tons per day by 2023). The proposed project will remove NOx RTCs by 14 tons per day by 2023. In addition, the proposed project is designed to implement both the Phase I and Phase II reduction commitments described in #CMB-01.

5. Although the proposed project also has the largest amount of adverse environmental impacts overall when compared to the alternatives, it achieves the maximum level of NOx reductions and corresponding health benefits.

6. Considering the need for expeditious improvement in air quality, the proposed project is preferred over the other alternatives considered because it provides the best balance between reducing NOx emissions relative to the adverse impacts.

7. Implementing the control measures in the 2012 AQMP will result in an overall net reduction in criteria pollutant emissions. Therefore, cumulative air quality impacts from the proposed project and all other AQMP control measures when considered together, are not expected to

be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement.

The SCAQMD's Governing Board finds that the above-described considerations outweigh the unavoidable significant effects to the environment as a result of the proposed project.

MITIGATION MONITORING PLAN

When making findings as required by Public Resources Code §21081 and CEQA Guidelines §15091, the lead agency must adopt a reporting or monitoring program for the changes to the project which it has adopted or made a condition of project approval in order to mitigate or avoid significant effects on the environment. [Public Resources Code §21081.6 and CEQA Guidelines §15097 (a)]. To fulfill the requirements of Public Resources Code §21081.6 and CEQA Guidelines §15097, the SCAQMD has developed this mitigation monitoring plan for anticipated impacts resulting from implementing the proposed project. Each operator of any facility required to comply with a mitigation monitoring plan shall keep records onsite of applicable compliance activities to demonstrate the steps taken to assure compliance with all of the mitigation measures, as applicable.

1. **Air Quality Impacts During Construction**

Impacts Summary: Project-specific and cumulative construction-related emissions of VOC, NOx, CO, PM10, and PM2.5 emissions, based on a "worst-case" analysis, would exceed the SCAQMD's regional mass daily significance thresholds for these pollutants. Emission sources include worker vehicles and heavy construction equipment. The following mitigation measures are intended to minimize the emissions associated with these sources during construction activities. No feasible mitigation measures have been identified to reduce emissions to a level of insignificance.

Mitigation Measures: The following construction mitigation measures are required for each of the affected facilities whose operators choose to install NOx control equipment. SCAQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

On-Road Mobile Sources

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to SCAQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

<u>Off-Road Mobile Sources:</u>

AQ-2 Maintain construction equipment tuned to manufacturer's recommended specifications that optimize emissions without nullifying engine warranties.

AQ-3 The project proponent shall survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 For all construction areas that are demonstrated to be served by electricity, use electricity for on-site mobile equipment instead of diesel equipment to the extent feasible. For example, electric welders should be used in lieu of diesel or gasoline-fueled welders and onsite electricity should be used in lieu of temporary power generators. If electricity is not available, use alternative fuels where feasible.

AQ-5 All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6 Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts as defined in SCAQMD Rule 701.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

Implementing Parties: The SCAQMD's Governing Board finds that implementing the mitigation measures AQ-1 through AQ-6 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures AQ-1 through AQ-6. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRAQ-1: Construction Emission Management Plan
Each facility operator shall develop and submit a Construction Emission Management Plan to the SCAQMD for approval prior to starting construction activities. Upon approval, each facility operator shall train all personnel subject to the requirements set forth in the Construction Emission Management Plan on how to comply with the requirements in the plan, and document that training. The SCAQMD may conduct routine inspections of the site to verify compliance. The Construction Emission Management Plan shall include, at a minimum, the following information:

- A construction schedule of activities for each construction phase that indicates the number of construction workers needed, and the type, fuel source, and number of construction equipment needed for each construction phase;
- A description of truck routing with a priority given to consolidating truck deliveries and scheduling deliveries to avoid peak hour traffic conditions;
- A format or system for logging delivery dates, times, and type of deliveries;
- A description of entry/exit points to the construction site;
- An identification of parking locations at the construction site; and,
- A description of how the prohibition of truck idling in excess of five consecutive minutes or another time-frame as allowed by the CCR Title 13 §2485, will be conveyed to truck drivers.

<u>Traffic Control</u>
Traffic requiring entrance onto each facility's property will be directed toward the entry gate or gates, if there are multiple entrances, so that congestion, as well as associated air pollution, will be minimized.

Points of entry will be selected to maximize facility security and reduce traffic-associated emissions. Each facility operator will direct their Receiving Department to consider delivery items, time of delivery, in-plant congested areas, surrounding area traffic, and gate security issues when assigning a gate entry location.

On-site parking will be used to the maximum extent available. In the event that off-site parking is required, construction workers may be requested to park at a designated off-site property. Buses or some other type of shuttle may transfer multiple workers at one time to and from the project site. No on-street parking (i.e., off of each facility's site) will be allowed.

Each facility operator will limit the number of personal and company vehicles allowed to enter each facility beyond the parking lots. This restriction helps minimize onsite emissions and promotes the use of ride sharing and alternate fueled transportation such as bicycles and electric golf carts.

<u>Construction Schedule</u>
In an effort to reduce traffic by construction workers, operators of the each facility may request its contractors to follow a compressed workweek. An example of a compressed workweek would be a four-day work week and a 10-hour work day with most work scheduled to begin by 7:00 a.m. and end after 5:30 p.m., Monday through Friday, to further minimize traffic congestion and related emissions. In addition, some work may need to be scheduled during the night shift, which will begin after 6:00 p.m. and end around 4:30 a.m. Critical path work may require a deviation from the aforementioned workweek and start- and stop-times; however, deviations will be minimized.

During process unit shutdowns, extended work shifts and night shifts, scheduled six to seven days per week, may be necessary. Each facility operator will establish in their Construction Emission Management Plan the details of the construction schedule, including operating hours, days, and number of shifts per day. This construction work schedule will need to be designed to minimize the travel time during peak travel periods.

<u>Trip Reduction Plan</u>
No feasible mitigation has been identified for the emissions from on-road vehicle trips. CEQA Guidelines §15364 defines feasible as "...capable of being accomplished in a successful manner." No feasible mitigation measures for offsite motor vehicles have been identified. Health and Safety Code §40929

prohibits the air districts and other public agencies from requiring an employee trip reduction program making such mitigation infeasible.

Delivery of Equipment and Materials
Each facility operator will coordinate the delivery of equipment and materials to avoid peak hour traffic, whenever possible. That is, delivery of construction materials to the site will be scheduled to occur during off-peak periods which are typically from 8:30 a.m. until 4:00 p.m. Monday through Friday. Each facility operator will request that equipment and material deliveries be minimized between the hours of 7:00 a.m. to 8:00 a.m. and 4:30 p.m. to 5:30 p.m. to reduce traffic in and out of each facility during high traffic peak times. Exceptions will be made for trucks carrying time-critical materials, e.g., concrete delivery and soil hauling (which eliminates the double handling or on-site stock-piling of soil, preventing it from being moved from place-to-place due to lack of adequate staging area, and subsequent removal at a later time via trucks). Delivery routes and schedules will be developed pursuant to the California Department of Transportation regulations.

It may be necessary to handle a limited amount of equipment as wide or special loads. These deliveries are subject to California Department of Transportation regulations and will be coordinated with local police departments. These trips will be scheduled to avoid peak hour traffic.

Prohibit Trucks From Idling Longer Than Five Minutes
Each facility operator will notify all vendors that during deliveries, truck idling time will be limited to no longer than five minutes or another time-frame as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. For any delivery that is expected to take longer than five minutes, each facility operator will require the truck's operator to shut off the engine. Each facility operator will notify the vendors of these delivery requirements at the time that the purchase order is issued and again when trucks enter the gates of the facility. To further ensure that drivers understand the truck idling requirement, signs will be posted at each facility entry gates stating idling longer than five minutes is not permitted.

MMRAQ-2: Maintain Construction Equipment, Tuned Up to Manufacturer's Recommended Specifications That Optimize Emissions Without Nullifying Engine Warranties

Each facility operator, in cooperation with the construction contractors, will maintain vehicle and equipment maintenance records for the construction portion of the proposed project. All construction vehicles must be maintained in compliance with the manufacturer's recommended maintenance schedule. Each facility operator will maintain their construction equipment and the construction contractor will be responsible for maintaining their equipment and maintenance records. All maintenance records for each facility and their construction contractor(s) will remain on-site for a period of at least two years from completion of construction.

MMRAQ-3: Survey of Construction Areas Where Electricity is Available for Operating Electric On-Site Mobile Equipment

Each facility operator and/or their construction contractor(s) will conduct a survey of the proposed project construction area(s) to assess whether the existing infrastructure can provide access to electricity, as available, within the facility or construction site, in order to operate electric on-site mobile equipment. For example, each facility operator and/or their construction contractor(s) will assess the number of electrical welding receptacles available.

Construction areas within the facility or construction site where electricity is and is not available must be clearly identified on a site plan as part of the Construction Emission Management Plan. The use of non-electric onsite mobile equipment shall be prohibited in areas of the facility that are shown to have access to electricity. The use of electric on-site mobile equipment within these identified areas of the facility or construction site will be allowed.

Each facility operator shall include in all construction contracts the requirement that the use of non-electric on-site mobile equipment is prohibited in certain portions of the facility as identified on the site plan. Each facility operator shall maintain records that indicate the location within the facility or construction site where all electric and non-electric on-site mobile equipment are operated, if at all, for a period of at least two years from completion of construction.

MMRAQ-4: Use Electricity or Alternate Fuels for On-Site Mobile Equipment Instead of Diesel Equipment to the Extent Feasible

Each facility operator and/or their construction contractor(s) shall evaluate the use of electricity and alternate fuels for on-site mobile construction equipment prior to the commencement of construction activities, provided that suitable equipment is available for the activity. Equipment vendors will be contacted to determine the commercial availability of electric or alternate-fueled construction equipment. Priority should be given to the use of electric on-site mobile construction equipment. If electricity is not available, then use alternative fuels to power on-site mobile construction equipment where feasible. Equipment that will use electricity or alternate fuels will be included in the Construction Emission Management Plan.

The potential equipment that may be considered includes, but is not limited to:

- Electric welders
- Electric scissor lifts
- Electric golf carts
- Bicycles
- Electric or bi-powered boom lifts

MMRAQ-5: All Off-Road Diesel-Powered Construction Equipment Greater Than 50 hp Shall Meet Tier 4 Off-Road Emission Standards and Shall Be Equipped With CARB-Certified Best Available Control Technology (BACT) Emissions Control Devices

Each facility operator shall include in all construction contracts the requirement that all off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. In addition, construction equipment shall incorporate, where feasible, emissions savings technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

MMRAQ-6: Suspend All Construction Activities That Generate Air Emissions During First Stage Smog Alerts

If and when any first stage smog alert or greater occurs, each facility operator will record the date and time of each alert, will suspend all construction activities that generate emissions, and will record the date and time when the use of construction equipment and construction activities are suspended. This log shall be maintained on-site for a period of at least two years from completion of construction.

2. <u>GHG Impacts</u>

Impact Summary: Based on a "worst-case" analysis, none of the affected facilities individually exceed the industrial GHG significance threshold. However, if the proposed project gets implemented, the analysis indicates that there will be a significant increase in GHG emissions for the project as a whole. Because there are significant adverse GHG impacts from the proposed project, the PEA must describe feasible measures which could minimize the significant adverse impacts. The following mitigation measures are intended to minimize the GHG emissions associated with water conveyance. No feasible mitigation measures have been identified to reduce GHG emissions to a level of insignificance.

Mitigation Measures: The following mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. SCAQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

GHG-1: When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

GHG-2: In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be supplied to the project.

Implementing Parties: The SCAQMD's Governing Board finds that implementing mitigation measures GHG-1 through GHG-2 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures GHG-1 through GHG-2. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRGHG-1: Use Recycled Water, If Available, for NOx Control Equipment That Requires Water for Its Operation
At the time of submitting an application for a Permit to Construct for NOx control equipment and water is required for its operation, each facility operator shall submit a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to the NOx control equipment. Once the NOx control equipment becomes operational, on a monthly basis, each facility operator will record the amount of recycled water delivered to the NOx control equipment from the recycled water bill. This log shall be maintained on-site for a period of at least two years from initiating operation.

MMRGHG-2: Submit Written Declaration if Recycled Water is Not Available
The facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

3. <u>Water Demand Impacts</u>

Impacts Summary - Hydrotesting: Some NOx control equipment may also require the installation of support equipment such as storage tanks, for example, which need to undergo hydrotesting in order to verify the structural integrity prior to operation. Because hydrotesting can utilize a substantial amount of water, significant adverse impacts associated with water demand during hydrotesting are expected from the proposed project post-construction but prior to operation. For example, for any facility that installs NOx control equipment that also requires the installation of support equipment, such as a storage tank or other equipment, to be installed and hydrotested as part of the proposed project, the use of non-potable water such as recycled water or diverted process water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water or diverted non-potable process water are required to use recycled water or diverted non-potable process water.

The water demand analysis during hydrotesting shows that the potential increase in potable water use cannot be fully supplied entirely with recycled water because recycled water is not currently delivered to all of the affected facilities. While there are ongoing negotiations to connect some of the affected facilities to recycled water at a future date, there are currently no contractual commitments in place to bring recycled water to these facilities. Further, for the facilities that currently have access to recycled water, there are currently no contractual commitments in place with the recycled water purveyors to provide an increased amount of recycled water deliveries above the existing baseline, even though there is plenty of recycled water supply available, to accommodate the increased demand for hydrotesting water that may result from the proposed project. Also, the potential increase in potable water use for hydrotesting cannot be fully supplied entirely by other non-potable water such as diverted process water because not all of the facilities have on-site sources of process water that can be diverted for hydrotesting purposes. Thus, some potable water may still be required to conduct hydrotesting.

In conclusion, because potable water may still be needed in the event that recycled water or other non-potable process water may not be available to all of the affected facilities, the analysis conservatively assumes that the water demand impacts during hydrotesting could remain significant after mitigation.

Because there are significant adverse water demand impacts from the proposed project post-construction but prior to operation during hydrotesting of support equipment, the PEA must describe feasible measures which could minimize the significant adverse impacts for hydrotesting activities. The following mitigation measures are intended to minimize the amount of potable water used for hydrotesting by requiring either recycled water or other non-potable water as a substitute, but the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to these alternate water sources. While the following feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of the aforementioned limitations with access to either recycled water or other non-potable water.

Mitigation Measures for Hydrotesting: The following water demand mitigation measures are required during hydrotesting for any facility that installs NOx control equipment with support equipment that requires hydrotesting prior to its operation as part of the proposed project. SCAQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

HWQ-1 When support equipment such as a storage tank is installed to support operations of installed NOx control equipment and hydrotesting is required prior to operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, in the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used, the facility operator is required to submit two written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

Impacts Summary – Operation of Air Pollution Control Equipment: Of the technologies proposed as BARCT for NOx control, only wet gas scrubber (WGS) technology utilizes water as part of their day-to-day operations and the amount of water needed on a daily basis is substantial and exceeds the significance threshold for potable water. Thus, significant adverse impacts associated with water demand during operation of WGSs are also expected from the proposed project. However, for any facility that installs NOx control equipment that also requires water for its operation, the use of recycled water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water are required to use recycled water instead of potable water. SCAQMD staff has verified that the water supply projections made by the water purveyors that provide water to the affected sources will be able to supply either potable water or recycled water, as applicable, to satisfy the potential water demand needs of the proposed project. However, the water demand analysis during operation shows that the potential increase in potable water use cannot be fully replaced with all recycled water because recycled water is not currently delivered to all of the affected facilities. While there are ongoing negotiations to connect some of the affected facilities to recycled water at a future date, there are currently no contractual commitments in place to bring recycled water to these facilities. Further, for the facilities that currently have access to recycled water, there are currently no contractual commitments in place with the recycled water purveyors to provide an increased amount of recycled water deliveries above the existing baseline. Thus, some potable water may still be required to operate air pollution control equipment.

In conclusion, because potable water may still be needed in the event that recycled water may not be available to all of the affected facilities, the analysis conservatively assumes that the water demand impacts during operation could remain significant after mitigation.

Because there are significant adverse water demand impacts from the proposed project during operation, the PEA must describe feasible measures which could minimize the significant adverse water demand impacts during operation. The following mitigation measures are intended to minimize the amount of potable water used for operating air pollution control equipment by requiring recycled water, but the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to recycled water, even if plenty of recycled water is available. While the following feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of the aforementioned limitations with access to recycled water.

Mitigation Measures for Operations of NOx Control Equipment That Utilizes Water: The following water demand mitigation measures are required during operation of any WGS or any other type of NOx control equipment that utilizes water for its operation that is installed as part of the proposed project.

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

Implementing Parties: The SCAQMD's Governing Board finds that implementing the mitigation measures HWQ-1 through HWQ-4 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures HWQ-1 through HWQ-4. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRHWQ-1: USE RECYCLED WATER OR OTHER NON-POTABLE PROCESS WATER, IF AVAILABLE, FOR HYDROTESTING

At the time of submitting an application for a Permit to Construct for NOx control equipment and any support equipment such as storage tank or other equipment that requires hydrotesting, each facility operator shall submit one of the following: 1) a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to conduct hydrotesting; or, 2) a supplement to the application(s) that describes how other non-potable process water will be diverted for hydrotesting. Once hydrotesting is complete, each facility operator will record one of the following: 1) the amount of recycled water delivered for hydrotesting from the recycled water bill; or 2) the amount of diverted process water used for hydrotesting. This log shall be maintained on-site for a period of at least two years from conducting hydrotesting.

MMRHWQ-2: SUBMIT WRITTEN DECLARATION IF RECYCLED WATER AND OTHER NON-POTABLE PROCESS WATER IS NOT USED FOR HYDROTESTING

The facility operator is required to submit two written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

MMRHWQ-3: USE RECYCLED WATER, IF AVAILABLE, FOR NOX CONTROL EQUIPMENT THAT REQUIRES WATER FOR ITS OPERATION

At the time of submitting an application for a Permit to Construct for NOx control equipment that requires water for its operation, each facility operator shall submit a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to the NOx control equipment. Once the NOx control equipment becomes operational, on a monthly basis, each facility operator will record the amount of recycled water delivered to the NOx control equipment from the recycled water bill. This log shall be maintained on-site for a period of at least two years from initiating operation.

MMRHWQ-4: SUBMIT WRITTEN DECLARATION IF RECYCLED WATER IS NOT AVAILABLE FOR NOX CONTROL EQUIPMENT THAT REQUIRES WATER FOR ITS OPERATION

The facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

CONCLUSION

Based on a “worst-case” analysis, the potential adverse construction air quality impacts, GHG impacts, water demand impacts, and hazards and hazardous materials impacts due to deliveries of ammonia from the adoption and implementation of the proposed project are considered significant and unavoidable. Feasible mitigation measures have been identified for construction air quality impacts, GHG impacts, and water demand impacts that would reduce these impacts associated with the proposed project; however, the mitigation measures are not sufficient to reduce the impacts to insignificance. No feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to hazards and hazardous materials due to deliveries of ammonia.

Further, none of the alternatives analyzed would reduce the construction air quality impacts, GHG impacts, water demand impacts, and hazards and hazardous materials impacts due to deliveries of ammonia to less than significant. As a result, no other feasible mitigation measures or project alternatives have been identified that would further reduce these impacts while still achieving the overall objectives of the proposed project.

(Adopted October 15, 1993)(Amended December 7, 1995)
(Amended February 14, 1997)(Amended May 11, 2001)(Amended January 7, 2005)
(Amended May 6, 2005)(Amended December 4, 2015)

RULE 2001. APPLICABILITY

(a) Purpose

This rule specifies criteria for inclusion in RECLAIM for new and existing facilities. It also specifies requirements for sources electing to enter RECLAIM and identifies provisions in District rules and regulations that do not apply to RECLAIM sources.

(b) Criteria for Inclusion in RECLAIM

The Executive Officer will maintain a listing of facilities which are subject to RECLAIM. The Executive Officer will include facilities, unless otherwise exempted pursuant to subdivision (i), if emissions fee data for 1990 or any subsequent year filed pursuant to Rule 301 - Permit Fees, shows four or more tons per year of NO_X or SO_X emissions where:

(1) NO_X emissions do not include emissions from:

(A) any NO_X source which was exempt from permit pursuant to Rule -219 Equipment Not Requiring A Written Permit Pursuant to Regulation II;

(B) any NO_X process unit which was rental equipment with a valid District Permit to Operate issued to a party other than the facility;

(C) on-site, off-road mobile sources; or

(D) ships as specified in Rule 2000(c)(62)(C) and (D).

(2) SO_X emissions do not include emissions from:

(A) any SO_X source which was exempt from permit pursuant to Rule -219 Equipment Not Requiring A Written Permit Pursuant to Regulation II; or

(B) any SO_X source that burned natural gas exclusively, unless the emissions are at a facility that elected to enter the program pursuant to subparagraph (i)(2)(A); or

(C) any SO_X process unit which was rental equipment with a valid District Permit to Operate issued to a party other than the facility;

(D) on-site, off-road mobile sources; or

(E) ships as specified in Rule 2000(c)(62)(C) and (D).

The Executive Officer will not include a facility in RECLAIM if a permit holder requests exclusion no later than January 1, 1996 and demonstrates prior to October 15, 1993 through the addition of control equipment, the possession of a valid Permit to Construct for such control equipment, or a Permit to Operate condition that the emissions fee data received pursuant to Rule 301, which shows emissions equal to or greater than four tons per year of a RECLAIM pollutant, is not representative of future emissions.

(c) Amendments to RECLAIM Facility Listing

(1) The Executive Officer will amend the RECLAIM facility listing to add, delete, change designation of any facility or make any other necessary corrections upon any of the following actions:

(A) Approval by the Executive Officer pursuant to Rule 2007 - Trading Requirements, of the permanent transfer or relinquishment of all RTCs applicable to a facility.

(B) Approval by the Executive Officer of a change of Facility Permit holder or change of facility name.

(C) Approval by the Executive Officer of a Facility Permit for a new facility if such new facility would, under RECLAIM, have a starting Allocation equal to or greater than four tons per year of a RECLAIM pollutant NO_X or SO_X, unless the facility would be exempt pursuant to subdivision (i).

(D) Approval by the Executive Officer of a Facility Permit for an existing non-RECLAIM facility, which reports NO_X or SO_X emissions pursuant to Rule 301 - Permit Fees, for any year which are equal to or greater than four tons, as specified in subdivision (b), unless the facility would be exempt pursuant to subdivision (i).

(E) Approval by the Executive Officer of the election of a facility to enter the RECLAIM program pursuant to subdivision (f).

(F) Upon delegation of authority from EPA to the District for Outer Continental Shelf (OCS) sources and inclusion of RECLAIM in 40 CFR Part 55 pursuant to the consistency update process, such OCS sources shall be RECLAIM facilities. The OCS sources' starting Allocation for the year of entry and Allocations for the years 2000 and 2003 and interim years, shall be determined pursuant to Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X), except that fuel usage and emissions data reported to the Minerals Management Service of the Department of the Interior be utilized where emissions data reported pursuant to Rule 301 is not available, provided that the permit holder substantiates the accuracy of such fuel usage and emissions data. The starting Allocation shall be adjusted to reflect the rate of reduction which would have been applicable to the facility if it had been in the RECLAIM program as of October 15, 1993.

(2) The actions specified in this subdivision shall be effective only upon amendment of the Facility Listing.

(d) Cycles

(1) The Executive Officer will assign RECLAIM facilities to one of two compliance cycles by computer-generated random assignment which, to the extent possible, ensures an even distribution of RTCs. The Facility Listing will distinguish between Cycle 1 facilities, which will have a compliance year of January 1 to December 31 of each year, and Cycle 2 facilities, with a compliance year of July 1 to June 30 of each year.

(2) The issue and expiration dates of the RTCs allocated to a facility shall coincide with the beginning and ending dates of the facility's compliance year.

(3) Within 30 days of October 15, 1993, facilities assigned to Cycle 2 may petition the Executive Office or the Hearing Board to change their cycle designation. Facilities assigned to Cycle 1 may not petition the Executive Officer or Hearing Board to change their cycle designation. Facilities entering the RECLAIM program after October 15, 1993 will be assigned to the cycle with the greatest amount of time remaining in the compliance year.

(e) High Employment/Low Emissions (HILO) Facility Designation

A new facility may, after January 1, 1997 apply to the District for classification as a HILO Facility. The Executive Officer will approve the HILO designation upon the determination that the emission rate for NO_X, SO_X, ROC, and PM_{10} is less than or equal to one-half (1/2) of any target specified in the AQMP for emissions per full-time manufacturing employee by industry class in the year 2010.

(f) Entry Election

(1) A non-RECLAIM facility may elect to permanently enter the RECLAIM program, provided that:

(A) the owner or operator files an Application for Entry;

(B) the facility is not listed as exempt under paragraph (i)(1);

(C) the facility is not operating under an Order for Abatement or in violation of any District rule; and

(D) the facility is not subject to a compliance date in an existing rule within six months of the date of Application for Entry.

(2) Upon approval of an Application for Entry, the Executive Officer will issue a Facility Permit. The facility's starting Allocation for the year of entry and Allocations for the years 2000 and 2003 and interim years, shall be determined pursuant to Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X). If necessary, the Allocation shall be adjusted to equal the Allocations which would have been applicable to the facility if it had been subject to the RECLAIM program as of October 15, 1993.

(3) Entry into the RECLAIM program will be effective upon issuance of a Facility Permit pursuant to Rule 2006 - Permits, and publication of the addition of the facility to the Facility Listing.

(g) Exit from RECLAIM

(1) The owner or operator of an electricity generating facility (EGF) may submit a plan application (i.e., opt-out plan) subject to plan fees specified in Rule 306 to request to opt-out of the NOx RECLAIM program provided that the following requirements are met as demonstrated in an opt-out plan submitted to the Executive Officer:

(A) At least 99 percent of the EGF's NOx emissions for the most recent three full compliance years are from equipment that meets current Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT), for NOx.

(B) The EGF is subject to NOx RECLAIM as of [*date of amendment*] or has been subject to NOx RECLAIM for at least 10 years as of the plan submittal date.

For the purpose~~s~~ of this rule an electricity generating facility (EGF) is a NOx RECLAIM facility that generates electricity for distribution in the state or local grid system, excluding cogeneration facilities.

(2) If the Executive Officer approves an opt-out plan, based on the criteria specified in paragraph (g)(1), then the EGF Facility Permit holder shall submit applications to include in its permit and accept permit conditions that ensure all of the following apply:

(A) NOx RTCs held by the EGF shall be treated as follows:

(i) For an EGF~~*s for which all permits were issued on or after January 1, 1994*~~ that does not meet the definition of an existing facility, as defined in Rule 2000(c)(35), the quantity of NOx RTCs for all compliance years after the date of approval of the opt-out plan required to be held by the EGF pursuant to Rule 2005 – New Source Review for RECLAIM shall be surrendered by the facility, retired from the market, and used to satisfy any NOx requirements for continuing obligations under Regulation XIII – New Source Review. If needed to equal this amount, any Non-tradable/Non-usable RTCs and any RTCs corresponding to the EGF's contribution to the Regional NSR Holding Account may be used for this purpose and, if RTCs from the Regional NSR Holding Account are used, these RTCs shall be removed from the Regional NSR Holding Account.

(ii) For existing EGFs, that meet the definition of an existing facility, as defined in Rule 2000(c)(35), an amount of NOx RTCs equivalent to the EGF's NOx holdings as of September 22, 2015 ~~*as*~~ adjusted pursuant to Rule 2002(f)(1) for all compliance years after the date of approval of the opt-out plan shall be surrendered by the EGF and retired from the market.

(iii) Any NOx RTCs held by an EGF beyond those referred to in clauses (i) and (ii) above may be sold, traded, or transferred by the facility.

(B) The EGF operator shall ensure that all equipment identified in the opt-out plan as meeting BACT or BARCT shall not exceed the respective BACT or BARCT levels of emissions or any existing permit condition limiting NOx emissions that is lower than BACT or BARCT as of the date of the opt-out plan submittal.

(C) Limits on EGF Emissions ~~*For existing EGFs, total facility emissions shall be limited to the amount of Compliance Year 2015 RTCs held as of September 22, 2015. The facility NOx emission limit shall be apportioned to each NOx source in the same proportion as its share of the EGF's emissions during the three complete compliance years prior to the date of opt-out plan submittal.*~~

(i) For an EGF that meets the definition of an existing facility in Rule 2000(c)(35), total facility emissions shall be limited to the amount of Compliance Year 2015 RTCs held as of September 22, 2015.

(ii) For an EGF that does not meet the definition of an existing facility in Rule 2000(c)(35), emissions from each NOx source shall be limited to the amount of RTCs required to be held for that source pursuant to Rule 2005 as of the date of opt-out plan approval.

(D) The owner or operator of multiple EGFs under common control shall have one opportunity to apportion the NOx emission limits among its facilities under common control for the purpose of meeting the requirements of clause (C)(i) or (C)(ii) as part of its opt-out plan as specified in paragraph (g)(1), provided all of the facilities opt out concurrently. The apportionment shall be described in the opt-out plan that shall be submitted to the Executive Officer. Each facility shall not have a limit that exceeds the amount of emissions that can be generated by all equipment located at the facility. ~~*For EGFs for which all permits were issued on or after January 1, 1994, emissions from each NOx source shall be limited to the amount of RTCs required to be held for that source pursuant to Rule 2005 as of the date of the opt-out plan submittal.*~~

(E) Subdivision (j) shall not be applicable to the EGF for any equipment installed or modified after the date of approval of the opt-out plan, and for ~~existing~~ other equipment at the earliest practicable date but no later than three years after the date of approval of the opt-out plan except Regulation XIII – New Source Review shall apply upon permit issuance.

(F) Notwithstanding the requirements specified in subparagraph (g)(2)(E), ~~*T*~~the EGF operator shall continue to comply with the requirements of Rule 2012 and its associated protocols unless the Executive Officer has approved an alternative monitoring and recordkeeping plan which is sufficient to determine compliance with all applicable rules.

(G) Notwithstanding the requirements specified in subparagraph (g)(2)(E), ~~*F*~~for EGFs not subject to Regulation XXX, the EGF's permit shall be re-designated as an "opt-out facility permit" and shall remain in effect, subject to annual renewal, unless expired, revoked, or modified pursuant to applicable rules. The EGF operator shall continue to pay RECLAIM permit fees pursuant to Rule 301(l).

(3) The Executive Officer shall approve or deny the opt-out plan within 180 days of receipt of a complete plan, unless the EGF and the Executive Officer have mutually agreed upon a longer time period. The Executive Officer shall not approve the opt-out plan unless it has been determined that the requirements of subparagraphs (g)(1)(A) and (g)(1)(B) are met, and the EGF accepts appropriate permit conditions to ensure compliance with the requirements of subparagraphs (g)(2)(B) through (~~G~~H). If, within 180 days or within the mutually agreed upon time period of receiving a complete opt-out plan, the Executive Officer does not take action on ~~it~~the plan, the EGF may consider ~~it~~the plan denied. Executive Officer denial of an opt-out plan can be appealed to the Hearing Board. The Executive Officer shall not re-issue the facility permit removing the EGF from RECLAIM unless the EGF surrender~~ed~~s the required amount of RTCs pursuant to subparagraph (g)(2)(A). Removal from RECLAIM of an EGF with an approved opt-out plan is effective upon issuance of a facility permit incorporating the conditions specified in paragraph (g)(2).

(4) No facility, on the initial Facility Listing or subsequently admitted to RECLAIM, may opt out of the program, unless approved by the Executive Officer pursuant to paragraph (g)(3).

(h) Non-RECLAIM Facility Generation of RTCs

Non-RECLAIM facilities may not obtain RTCs due to a shutdown or curtailment of operations which occurs after October 15, 1993. ERCs generated by non-RECLAIM facilities may not be converted to RTCs if the ERCs are based on a shutdown or curtailment of operations after October 15, 1993.

(i) Exemptions

(1) The following sources, including those that are part of or located on a Department of Defense facility, shall not be included in RECLAIM and are prohibited from electing to enter RECLAIM:

(A) dry cleaners;

(B) fire fighting facilities;

(C) construction and operation of landfill gas control, processing or landfill gas energy recovery facilities;

(D) facilities which have converted all sources to operate on electric power prior to October 15, 1993;

(E) police facilities;

(F) public transit;

(G) restaurants;

(H) potable water delivery operations;

(I) facilities located in the Riverside County portions of the Salton Sea and Mojave Desert Air Basins, except for a facility that has elected to enter the RECLAIM program pursuant to subparagraph (i)(2)(M); and

(J) facilities that have permanently ceased operations of all sources before January 1, 1994.

(K) The facility was removed from RECLAIM pursuant to paragraph (g)(3).

(2) The following sources, including those that are part of or located on a Department of Defense facility, shall not be initially included in RECLAIM but may enter the program pursuant to subdivision (f):

(A) electric utilities (exemption only for the SO_X program);

(B) equipment rental facilities;

(C) facilities possessing solely "various location" permits;

(D) hospitals;

(E) prisons;

(F) publicly owned municipal waste-to-energy facilities;

(G) portions of facilities conducting research operations;

(H) schools or universities;

(I) sewage treatment facilities which are publicly owned and operated consistent with an approved regional growth plan;

(J) electric power generating systems owned and operated by the City of Burbank, City of Glendale or City of Pasadena or any of their successors;

(K) ski resorts;

(L) facilities located on San Clemente Island;

(M) any electric generating facility that has submitted complete permit applications for all equipment requiring permits at the facility on or after January 1, 2001 may elect to enter the NOx RECLAIM program if the facility is located in the Riverside County portions of the Salton Sea or Mojave Desert Air Basins; and

(N) facilities that are an agricultural source as defined in California Health and Safety Code § 39011.5~~.~~; and

(O) any EGF as defined in paragraph (g)(1), except for an EGF that has been removed from NOx RECLAIM, pursuant to paragraph (g)(3).

(j) Rule Applicability

Facilities operating under the provisions of the RECLAIM program shall be required to comply concurrently with all provisions of District rules and regulations, except those provisions applicable to NOx emissions under the rules listed in Table 1, shall not apply to NO_X emissions from NOx RECLAIM facilities, and those provisions applicable to SOx emissions of the rules listed in Table 2 shall not apply to SOx emissions from SOx RECLAIM facilities after the later of the following:

(1) December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities; or

(2) the date the facility has demonstrated compliance with all monitoring and reporting requirements of Rules 2011 or 2012, as applicable.

Notwithstanding the above, NOx and SOx RECLAIM facilities shall not be required to comply with those provisions applicable respectively to NOx and SOx emissions of the listed District rules in Tables 1 and 2 which have initial implementation dates in 1994. The Facility Permit holder shall comply with all other provisions of the rules listed in Table 1 and 2 relating to any other pollutant.

Table 1

EXISTING RULES
NOT APPLICABLE TO RECLAIM FACILITIES FOR
REQUIREMENTS PERTAINING TO NO_X EMISSIONS

RULE	DESCRIPTION
218	Stack Monitoring
429	Start-up & Shutdown Exemption Provisions for NO_X
430	Breakdown Provision
474	Fuel Burning Equipment - NO_X
476	Steam Generating Equipment
1109	Emis. of NO_X Boilers & Proc. Heaters in Petroleum Refineries
1110	Emis. from Stationary I. C. Engines (Demo.)
1110.1	Emis. from Stationary I. C. Engines
1110.2	Emis. from Gaseous and Liquid-Fueled I. C. Engines
1112	Emis. of NO_X from Cement Kilns
1117	Emis. of NO_X from Glass Melting Furnaces
1134	Emis. of NO_X from Stationary Gas Turbines
1135	Emis. of NO_X from Electric Power Generating Systems
1146	Emis. of NO_X from Boilers, Steam Generators, and Proc. Heaters
1146.1	Emis. of NO_X from Small Boilers, Steam Generators, and Proc. Heaters
1159	Nitric Acid Units - Oxides of Nitrogen
Reg. XIII	New Source Review

Table 2

EXISTING RULES
NOT APPLICABLE TO RECLAIM FACILITIES FOR
REQUIREMENTS PERTAINING TO SO_X EMISSIONS

RULE	DESCRIPTION
53	Sulfur Compounds - Concentration - L.A. County
53	Sulfur Compounds - Concentration - Orange County
53	Sulfur Compounds - Concentration - Riverside County
53	Sulfur Compounds - Concentration - San Bernardino County
53A	Specific Contaminants - San Bernardino County
218	Stack Monitoring
430	Breakdown Provisions
407	Liquid and Gaseous Air Contaminants
431.1	Sulfur Content of Gaseous Fuels
431.2	Sulfur Content of Liquid Fuels
431.3	Sulfur Content of Fossil Fuels
468	Sulfur Recovery Units
469	Sulfuric Acid Units
1101	Secondary Lead Smelters/Sulfur Oxides
1105	Fluid Catalytic Cracking Units SO_X
1119	Petroleum Coke Calcining Operations - Oxides of Sulfur
Reg. XIII	New Source Review

(Adopted October 15, 1993)(Amended March 10, 1995)(Amended December 7, 1995)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended May 11, 2001)
(Amended January 7, 2005)(Amended November 5, 2010)
(Amended December 4, 2015)

PROPOSED AMENDED RULE 2002. ALLOCATIONS FOR OXIDES OF NITROGEN (NO_X) AND OXIDES OF SULFUR (SOx)

(a) Purpose

The purpose of this rule is to establish the methodology for calculating facility Allocations and adjustments to RTC holdings for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).

(b) RECLAIM Allocations

(1) RECLAIM Allocations will begin in 1994.

(2) An annual Allocation will be assigned to each facility for each compliance year starting from 1994.

(3) Allocations and RTC holdings for each year after 2011 are equal to the 2011 Allocation and RTC holdings, as determined pursuant to subdivision (f) unless, as part of the AQMP process, and pursuant to Rule 2015 (b)(1), (b)(3), (b)(4), or (c), the District Governing Board determines that additional reductions are necessary to meet air quality standards, taking into consideration the current and projected state of technology available and cost-effectiveness to achieve further emission reductions.

(4) The Facility Permit or relevant sections thereof shall be re-issued at the beginning of each compliance year to include allocations determined pursuant to subdivisions (c), (d), (e), and (f) and any RECLAIM Trading Credits (RTC) obtained pursuant to Rule 2007 - Trading Requirements for the next fifteen years thereafter and any other modifications approved or required by the Executive Officer.

(5) Annual emission reports submitted pursuant to Rule 301 more than five years after the original due date shall not be considered by the Executive Officer in determining facility Allocations.

(c) Establishment of Starting Allocations

(1) The starting Allocation for RECLAIM NO_X and SO_X facilities initially permitted by the District prior to October 15, 1993, shall be determined by the Executive Officer utilizing the following methodology:

Starting Allocation=Σ[A X B_1]+ERCs+External Offsets

where

A = the throughput for each NO_X and SO_X source or process unit in the facility for the maximum throughput year from 1989 to 1992 inclusive; and

B_1 = the applicable starting emission factor for the subject source or process unit as specified in Table 1 or Table 2

(2) (A) Use of 1992 data is subject to verification and revision by the Executive Officer or designee to assure validity and accuracy.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports submitted pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable starting emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information relative to hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other relevant parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District, including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NOx or SOx source will be multiplied by the starting emission factors specified in Table 1 or Table 2. If a lower emission factor was utilized for a given piece of equipment or NOx or SOx source pursuant to Rule 301 - Permit Fees, than the factor in Table 1 or Table 2, the lower factor will be used for determining that portion of the Allocation.

(E) Fuel heating values may be used to convert throughput records into the appropriate units for determining Allocations based on the emission factors in Table 1 or Table 2. If a different unit basis than set forth in Tables 1 and 2 is needed for emissions calculations, the Executive Officer shall use a default heating value to determine source emissions, unless the Facility Permit holder can demonstrate with substantial evidence to the Executive Officer that a different value should be used to determine emissions from that source.

(3) All NO_X and SO_X ERCs generated at the facility and held by a RECLAIM Facility Permit holder shall be reissued as RTCs. RECLAIM facilities will have these RTCs added to their starting Allocations. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule and shall have a rate of reduction for compliance year 2004 and subsequent years determined pursuant to paragraph (f)(1) of this rule.

(4) Non-RECLAIM facilities may elect to have their ERCs converted to RTCs and listed on the RTC Listing maintained by the Executive Officer or designee pursuant to Rule 2007 - Trading Requirements, so long as the written request is filed before July 1, 1994. Such RTCs will be assigned to the trading zone in which the generating facility is located. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years, 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule.

(5) External offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio, will be added to the starting Allocation pursuant to paragraph (c)(1) provided:

(A) The offsets were not received from either the Community Bank or the Priority Reserve.

(B) External offsets will only be added to the starting Allocation to the extent that the Facility Permit holder demonstrates that they have not already been included in the starting Allocation or as an ERC. RTCs issued for external offsets shall not include any offsets in excess of a 1 to 1 ratio required under Regulation XIII - New Source Review.

(C) RTCs generated from the conversion of external offsets shall have a zero rate of reduction for the year 1994 through the year 2000. These RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule, and for compliance year 2004 and subsequent years allocations shall be determined pursuant to paragraph (f)(1) of this rule. The rate of reduction for the year 2001 through year 2003 shall not be applied to new facilities initially totally permitted on or after January 7, 2005.

(D) Existing facilities with units that have Permits to Construct issued pursuant to Regulation II - Permits, dated on or after January 1, 1992, or existing facilities which have, between January 1, 1992 and October 15, 1993, installed air pollution control equipment that was exempt from offset requirements pursuant to Rule 1304 (a)(5), shall have their starting Allocations increased by the total external offsets provided, or the amount that would have been offset if the exemption had not applied.

(E) Existing facilities with units whose reported emissions are below capacity due to phased construction, and/or where the Permit to Operate issued pursuant to Regulation II - Permits, was issued after January 1, 1992, shall have their starting Allocations increased by the total external offsets provided.

(6) If a Facility Permit holder can demonstrate that its 1994 Allocation is less than the 1992 emissions reported pursuant to Rule 301 - Permit Fees, and that the facility was, in 1992, operating in compliance with all applicable District rules in effect as of December 31, 1993, the facility's starting Allocation will be equal to the 1992 reported emissions.

(7) For new facilities initially totally permitted on or after January 1, 1993 but prior to October 15, 1993, the starting Allocation shall be equal to the external offsets provided by the facility to offset emission increases at the

facility pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(8) The Allocation for new facilities initially totally permitted on and after October 15, 1993, shall be equal to the total RTCs provided by the facility to offset emission increases at the facility pursuant to Rule 2005- New Source Review for RECLAIM.

(9) The starting Allocation for existing facilities which enter the RECLAIM program pursuant to Rule 2001 - Applicability, shall be determined by the methodology in paragraph (c)(1) of this rule. The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to the external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio. The Allocation shall not include any emission offsets received from either the Community Bank or the Priority Reserve.

(10) A facility may not receive more than one set of Allocations.

(11) A facility that is no longer holding a valid District permit on January 1, 1994 will not receive an Allocation, but may, if authorized by Regulation XIII, apply for ERCs.

(12) Clean Fuel Adjustment to Starting Allocation

Any refiner who is required to make modifications to comply with CARB Phase II reformulated gasoline production (California Code of Regulations, Title 13, Sections 2250, 2251.5, 2252, 2260, 2261, 2262, 2262.2, 2262.3, 2262.4, 2262.5, 2262.6, 2262.7, 2263, 2264, 2266, 2267, 2268, 2269, 2270, and 2271) or federal requirements (Federal Clean Air Act, Title II, Part A, Section 211; 42 U.S.C. Section 7545) may receive (an) increase(s) in his Allocations except to the extent that there is an increase in maximum rating of the new or modified equipment. Each facility requesting an increase to Allocations shall submit an application for permit amendment specifying the necessary modifications and tentative schedule for completion. The Facility Permit holder shall establish the amount of emission increases resulting from the reformulated gasoline modifications for each year in which the increase in Allocations is requested. The increase to its Allocations will be issued contemporaneously with the modification according to a schedule approved by the Executive Officer or designee (i.e., 1994 through 1997 depending on the refinery). Each increase to the Allocations shall be equal to the increased emissions resulting from the modifications solely to comply with the state or federal reformulated gasoline requirements at the refinery or facility producing hydrogen for reformulated gasoline production, and shall be established according to present and future compliance limits in current District rules or permits. Allocation increases for each refiner pursuant to this paragraph, shall not exceed 5 percent of the refiner's total starting Allocation, unless any refiner emits less than 0.0135 tons of NO_X per thousand barrels of crude processed, in which case the Allocation increases for such refiner shall not exceed 20 percent of that refiner's starting Allocation. The emissions per amount of crude processed will be determined on the basis of information reported to the District pursuant to Rule 301 - Permit Fees, for the same calendar year as the facility's peak activity year for their NO_X starting Allocation.

(d) Establishment of Year 2000 Allocations

(1) (A) The year 2000 Allocations for RECLAIM NO_X and SO_X facilities will be determined by the Executive Officer or designee utilizing the following methodology:

Year 2000 Allocation = Σ [A X B_2] + RTCs created from ERCs + External Offsets,

where

A = the throughput for each NO_X or SO_X source or process unit in the facility for the maximum throughput year from 1987 to 1992, inclusive, as reported pursuant to Rule 301 - Permit Fees; and

B_2 = the applicable Tier I year Allocation emission factor for the subject source or process unit, as specified in Table 1 or Table 2.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information on hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to

Construct, and other parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NO_X or SO_X source will be multiplied by the Tier I emission factor specified in Table 1 or Table 2. If a factor lower than the factor in Table 1 or Table 2 was utilized for a given piece of equipment or NO_X or SO_X source pursuant to Rule 301, the lower factor will be used for determining that portion of the Allocation.

(E) The fuel heating value may be considered in determining Allocations and will be set to 1.0 unless the Facility Permit holder demonstrates that it should receive a different value.

(F) The year 2000 Allocation is the sum of the resulting products for each piece of equipment or NO_X or SO_X source multiplied by any inventory adjustment pursuant to paragraph (d)(4) of this rule.

(2) For facilities existing prior to October 15, 1993 which enter RECLAIM after October 15, 1993, the year 2000 Allocation will be determined according to paragraph (d)(1). The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to their external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(3) No facility shall have a year 2000 Allocation [calculated pursuant to subdivision (d)] greater than the starting Allocation [calculated pursuant to subdivision (c)].

(4) If the sum of all RECLAIM facilities' year 2000 Allocations differs from the year 2000 projected inventory for these sources under the 1991 AQMP, the Executive Officer or designee will establish a percentage inventory adjustment factor that will be applied to adjust each facility's year 2000

Allocation. The inventory adjustment will not apply to RTCs generated from ERCs or external offsets.

(e) Allocations for the Year 2003

(1) The 2003 Allocations will be determined by the Executive Officer or designee applying a percentage inventory adjustment to reduce each facility's unadjusted year 2000 Allocation so that the sum of all RECLAIM facilities' 2003 Allocations will equal the 1991 AQMP projected inventory for RECLAIM sources for the year 2003, corrected based on actual facility data reviewed for purposes of issuing Facility Permits and to reflect the highest year of actual Basin-wide economic activity for RECLAIM sources considered as a whole during the years 1987 through 1992.

(2) No facility shall have a 2003 Allocation (calculated pursuant this subdivision) greater than the year 2000 Allocation [calculated pursuant to subdivision (d)].

(f) Annual Allocations for NO_X and SOx and Adjustments to RTC Holdings

(1) Allocations for the years between 1994 and 2000, for RECLAIM NO_X and SO_X facilities shall be determined by a straight line rate of reduction between the starting Allocation and the year 2000 Allocation. For the years 2001 and 2002, the Allocations shall be determined by a straight line rate of reduction between the year 2000 and year 2003 Allocations. NOx Allocations for 2004, 2005, and 2006 and SOx Allocations for 2004 through 2012 are equal to the facility's 2003 Allocation, as determined pursuant to subdivision (e). NOx RTC Allocations and holdings subsequent to the year 2006 and SOx Allocations and holdings subsequent to the year 2012 shall be adjusted to the nearest pound as follows:

(A) The Executive Officer will adjust NOx RTC holdings, as of January 7, 2005 for compliance years 2007 and thereafter by multiplying the amount of RTC holdings by the following adjustment factors for the relevant compliance year, to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance <u>Year</u>	Tradable/Usable NOx RTC Adjustment <u>Factor</u>	~~Non-tradable/ Non-usable NOx RTC Adjustment Factor~~
2007	0.883	~~0~~
2008	0.856	~~0.027~~
2009	0.829	~~0.054~~

2010	0.802	~~0.081~~
2011 and after~~and after through 2015~~	0.775	~~0.108~~

~~RTCs designated as non-tradable/non-usable pursuant to this subparagraph shall be held, but shall not be used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).~~

(B) The Executive Officer shall adjust NOx RTCs held as of September 22, 2015 by the RTC holders identified in Table 7 and their successors using the following adjustment factors to obtain Tradable/Usable and Non-Tradable/Non-Usable RTC Holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2015	1.0	0
2016	0.812	0.188
2017	0.812	0
2018	0.718	0.094
2019	0.625	0.093
2020	0.531	0.094
2021	0.437	0.094
2022	0.343	0.094
2023 and after	0.343	0

RTC holdings traded from RTC holders in Table 7 on and after~~since~~ September 22, 2015 and held by other RTC holders not listed in Table 7 shall be subjected to the above adjustment factors. ~~*For purposes of assigning the appropriate*~~ The adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and *[date of amendment]*~~,~~ shall be based on a last in/first out basis ~~*at the time each transaction was registered*~~.

(C) The Executive Officer shall adjust NOx RTCs held as of September 22, 2015 by the RTC holders identified in Table 8 and their successors using the following adjustment factors to obtain Tradable/Usable and Non-Tradable/Non-Usable RTC holdings:

Compliance	Tradable/Usable NOx RTC	Non-tradable/ Non-usable NOx RTC

Year	Adjustment Factor	Adjustment Factor
2015	1.0	0
2016	0.861	0.139
2017	0.861	0
2018	0.792	0.069
2019	0.722	0.07
2020	0.653	0.069
2021	0.583	0.07
2022	0.514	0.069
2023 and after	0.514	0

RTC holdings traded from RTC holders in Table 8 on and after September 22, 2015 and held by other RTC holders not listed in Table 8 shall be subjected to the above adjustment factors. ~~*For purposes of assigning the appropriate*~~ The adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and *[date of adoption]*~~,~~ shall be based on a last in/first out basis ~~*at the time each transaction was registered*~~.

(D) RTCs designated as non-tradable/non-usable pursuant to subparagraphs (f)(1)(B) and (f)(1)(C) shall be held, but shall not be traded or used for reconciling ~~for~~ emissions pursuant to Rule 2004. ~~The adjustment factors in this subparagraphs (f)(1)(B) and (f)(1)(C) are subject to change pursuant to paragraph (i)(5).~~

(~~B~~E) Commencing on January 1, 2008 with NOx RTC prices averaged from January 1, 2007 through December 31, 2007, the Executive Officer will calculate the 12-month rolling average RTC price for all trades for the current compliance year. Commencing on May 1, 2016 with NOx RTC prices averaged from January 1, 2016 through March 31, 2016, the Executive Officer will calculate the 3-month rolling average NOx RTC price for all trades for the current compliance year NOx RTCs and the 12-month rolling average NOx RTC price for all trades for infinite year block NOx RTC as defined in subparagraph (f)(1)(~~J~~I). The Executive Officer will update the 3-month and 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

~~*(F)*~~ ~~*At the conclusion of any of the compliance years 2016 through 2022 if the NOx RTC prices have not exceeded the $22,500 per*~~

~~*ton threshold as specified in subparagraph (f)(1)(I) and a State of Emergency related to electricity demand orf power grid stability within the SCAQMD jurisdictional boundaries as specified in paragraph (f)(4) has not been declared by the Governor, then the Non-tradable/Non-usable NOx RTCs for that compliance year, except for those RTCs specified in subparagraph (f)(1)(G), shall be submitted as part of the State Implementation Plan commitment.*~~

(~~G~~F) The Executive Officer shall transfer to a Regional NSR Holding account the amount of NOx RTCs holdings listed in Table 9 of this Rule from the corresponding facilities identified in the same table.

(~~H~~G) For purposes of meeting the NSR holding requirement as specified in subdivision (f) of Rule 2005, the facilities identified in Table 9 may use a combination of their Tradable/Usable and Non-tradable/Non-usable RTCs specified in subparagraph (f)(1)(C) and the amount listed for each facility in Table 9, which represents the RTCs in the Regional NSR Holding account.

(~~C~~IH) ~~Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(A), i~~In the event that the NOx RTC prices exceed ~~$15,000~~$22,500 per ton (~~*discrete*~~ current compliance year credits) based on the 12-month rolling average, or exceed $35,000 per ton (~~*discrete*~~ current compliance year credits) based on the 3-month rolling average calculated pursuant to subparagraph (f)(1)(~~B~~E), the Executive Officer will report the determination to the Governing Board. If the Governing Board finds that the 12-month rolling average RTC price exceeds ~~$15,000~~$22,500 per ton or the 3-month rolling average RTC price exceeds $35,000 per ton, then the ~~incremental~~ Non-tradable/Non-usable NOx ~~reductions~~ RTCs, as specified in subparagraphs (f)(1)(~~D~~B) and (f)(1)(C) valid for the period in which the RTC price is found to have exceeded the applicable threshold,~~*compliance year in which Cycle 1 facilities are currently operating*~~ shall be -converted to Tradable/Usable NOx RTCs upon Governing Board concurrence.

(~~J~~I) In the event that the infinite year block NOx RTC prices fall below $200,000 per ton based on the 12-month rolling average, calculated pursuant to subparagraph (f)(1)(E) beginning in 2019 for the compliance year in which Cycle 1 facilities are operating, the Executive Officer will report the determination to the Governing Board.

For the purpose of this rule, infinite year block refers to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

(~~K~~J) Pursuant to subparagraphs (f)(1)(~~I~~H) and (f)(1)(~~J~~I) ~~The~~ the Executive Officer's report to the Board will also include a commitment and schedule to conduct a more rigorous control technology implementation, emission reduction, cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program. The Executive Officer's report to the Board will be made at a public hearing at the earliest possible regularly scheduled Board Meeting, but no more than ~~60~~ 90 days from Executive Officer determination.

~~(D) The incremental NOx RTCS restored shall be the difference between the Non-tradable/Non-usable Adjustment Factors, as specified in subparagraph (f)(1)(A), of the current compliance year and the most recent prior year the adjustment factor was implemented.~~

~~(E) RTC conversion pursuant to subparagraph (f)(1)(C) shall only occur in the compliance year in which Cycle 1 facilities are operating.~~

~~(F) Notwithstanding the adjustment factors required pursuant to subparagraph (f)(1)(A), beginning with the following December and each year thereafter that the Governing Board finds the $15,000 per ton NOx RTC price is exceeded pursuant to subparagraph (f)(1)(C), the Executive Officer will publish the applicable adjustment factors for the next compliance year beginning January 1. The adjustment factors will be published at a public hearing during a regularly scheduled Board Meeting. The adjustment factors will be determined as follows:~~

~~(i) If the 12-month rolling average falls below $15,000 per ton for at least 6 consecutive months, then the emission adjustment factors for the following compliance year shall equal the next more stringent adjustment factors listed in subparagraph (f)(1)(A) than the factors currently in effect; otherwise;~~

~~(ii) The next compliance year adjustment factors shall equal the compliance year adjustment factors currently in place.~~

~~The Executive Officer need no longer comply with the annual public hearing requirement once the adjustment factors for the 2010 compliance year have been implemented for a 12-month period.~~

(~~G~~~~L~~K) The NOx *emission reductions associated with the* RTC adjustment factors for compliance years 20~~08~~16, and 2018 through 20~~10~~22 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. However, the amount of NOx RTCs adjustments specified in sub-paragraph (f)(1)(~~G~~F) shall not be submitted for inclusion in the State Implementation Plan. ~~The 2011 NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year.~~

(~~H~~~~M~~L) NOx Allocations for existing facilities that enter RECLAIM after (*date of adoption*) for Compliance Year 2016 and all subsequent years shall be the amount determined pursuant to subparagraph (d)(1)(A) except the variable B2 shall be the lowest of:

(i) The applicable 2000 (Tier I) Ending Emission Factor for the subject source(s) or process unit(s), as specified in Table 1 multiplied by the percentage inventory adjustment pursuant to subdivision (e) (0.72~~8~~);

(ii) The BARCT Emission factor for the subject source as specified in Table 3; and

(iii) The BARCT Emission factor for the subject ~~as~~ source, as specified in Table 6.

~~NOx Allocations for facilities that enter RECLAIM after January 7, 2005 for compliance years 2007 and after shall be determined by applying the Tradable/Usable and Non-tradable/Non-usable NOx RTC Adjustment Factors under subparagraph (f)(1)(A) to the facility's Compliance Year 2006 Allocation.~~

(~~I~~NM) SOx RTC Holdings as of November 5, 2010, for compliance years 2013 and after shall be adjusted to achieve an overall reduction in the following amounts:

Compliance Year	Minimum emission reductions (lbs.)
2013	2,190,000
2014	2,920,000
2015	2,920,000
2016	2,920,000
2017	3,650,000
2018	3,650,000
2019 and after	4,161,000

(~~J~~ON) The Executive Officer shall determine Tradable/usable SOx RTC Adjustment Factor~~s~~ for each compliance year~~s~~ after 2012 as follows:

$$F_{\text{compliance year i}} = 1 - [Xi / (Ai + Bi + Ci)]$$

Where:

$F_{\text{compliance year i}}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year i starting with 2013

Ai = Total SOx RTCs for compliance year i held as of November ~~11~~5, 2010, by all RTC holders, except those listed in Table 5

Bi = Total SOx RTCs for compliance year i credited to any facilities listed in Table 5 between August 29, 2009 and ~~(rule adoption date)~~November 5, 2010, and not included~~s~~ in Ci

Ci = Total SOx RTCs held as of ~~(rule adoption date)~~November 5, 2010 by facilities listed in Table 5 for compliance year i in excess of allocations as determined pursuant to subdivision (e).

Xi = Amount to be reduced for compliance year i starting with 2013 as listed in subparagraph (f)(1)(~~I~~NM).

(~~KP~~O) The Executive Officer shall determine Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2017 through 2019 as follows:

$$N_{\text{compliance year j}} = F_{\text{compliance year 2016}} - F_{\text{compliance year j}}$$

Where:

$N_{\text{compliance year j}}$ = Non-tradable/Non-usable SOx RTC Adjustment Factor for compliance year j

$F_{\text{compliance year j}}$ = Tradable/Usable SOx RTC Adjustment Factor for compliance year j as determined pursuant to subparagraph (f)(1)(~~J~~O~~N~~)

j = 2017 through 2019

$F_{\text{compliance year 2016}}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year 2016 as determined pursuant to subparagraph (f)(1)(~~J~~O~~N~~)

Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2013, 2014, 2020, and all years after 2020 shall be 0.0.

(~~L~~QP) The Executive Officer shall adjust the SOx RTC holdings as of November 5, 2010, for compliance years 2013 and after as follows:

(i) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{\text{compliance year i}}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{\text{compliance year j}}$) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~RQ) to SOx RTC holdings held by any RTC holder except those listed in Table 5;

(ii) Apply no adjustment to SOx RTC holdings that are held as of August 29, 2009 by a facility listed in Table 5, and that are less than or equal to the facility's allocations as determined pursuant to subdivision (e), and that were not credited between August 29, 2009 and November 5, 2010;

(iii) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~~~R~~Q) to any SOx RTC holding as of ~~(~~November 5, 2010~~)~~, that is held by a facility that is listed in Table 5, and that is over the facility's allocations as determined pursuant to subdivision (e); and

(iv) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~~~R~~Q) to any SOx RTC holding that was acquired between August 29, 2009 and November 5, 2010, by a facility that is listed in Table 5.

No SOx RTC holding shall be subject to the SOx RTC adjustments as published under subparagraph (f)(1)(~~M~~~~R~~Q) more than once.

(~~M~~~~R~~Q) The Executive Officer shall publish the SOx RTC Adjustment Factors determined according to subparagraphs (f)(1)(~~J~~~~O~~N) and (f)(1)(~~K~~~~P~~O) within 30 days after November 5, 2010.

(~~N~~~~S~~R) Commencing on January 1, 2017 and ending on February 1, 2020, the Executive Officer will calculate the 12-month rolling average SOx RTC price for all trades during the preceding 12 months for the current compliance year. The Executive Officer will update the 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(~~O~~~~T~~S) In the event that the SOx RTC prices exceed $50,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(~~N~~~~S~~R), the Executive Officer will report to the Governing Board at a duly noticed public hearing to be held no more than 60 days from Executive Officer determination. The Executive Officer will announce that determination on the SCAQMD website. At the public hearing, the Governing Board will decide whether or not to convert any portion of the Non-tradable/Non-usable RTCs, as determined pursuant to subparagraphs (f)(1)(~~K~~~~P~~<u>O</u>) and (f)(1)(~~L~~~~Q~~<u>P</u>), and how much to convert if any, to Tradable/Usable RTCs. The portion of Non-tradable/Non-usable RTCs available for conversion to Tradable/Usable RTCs shall not include any portion of Non-tradable/Non-usable RTCs that are designated for previous compliance years and has not already been converted by the Governing Board, or that has been otherwise included in the State Implementation Plan pursuant to subparagraph (f)(1)(~~P~~~~U~~<u>T</u>).

(~~P~~~~U~~<u>T</u>) The Executive Officer will not submit the emission reductions obtained through subparagraph (f)(1)(~~I~~~~N~~<u>M</u>) for compliance years 2017 through 2019 for inclusion into the State Implementation Plan until the adjustments for the RTC Holdings have been in effect for one full compliance year.

(~~Q~~~~V~~<u>U</u>) SOx Allocations for compliance years 2013 and after, for facilities that enter RECLAIM after November 5, 2010, and for basic equipment listed in Table 4 shall be determined according to the BARCT level listed in Table 4 or the permitted emission limits, whichever is lower.

(<u>V</u>) <u>By no later than July 1, 2012, SOx emissions at the exhaust of a Fluidized Catalytic Cracking Unit, as measured at the final stack venting gases originating from the facility's FCC Regenerator, including after the CO Boiler or any additional controls in the system following the regenerator (the final stack shall constitute the only exhaust gas compliance point within the FCCU facility), shall not exceed a concentration of 25 ppm dry @ 0% oxygen on a 365-day rolling average. The numeric concentration-based limit does not apply during time periods in which SOx data are determined to be incorrect due to analyzer calibration or malfunction. For the purpose of demonstrating compliance with this limit, the operator of a FCCU shall commence the use of SOx reducing additives in the FCCU no later than July 1, 2011, unless the operator has an existing wet gas scrubber in operation at BARCT levels prior to November 5, 2010 or can demonstrate to the Executive Officer that the FCCU will achieve this limit by using other control methods.</u>

(2) New facilities initially totally permitted, on and after October 15, 1993, but prior to January 7, 2005, and entering the RECLAIM program after January 7, 2005 shall not have a rate of reduction until 2001. Reductions from 2001 to 2003, inclusive, shall be implemented pursuant to subdivision (e). New facilities initially totally permitted on or after January 7, 2005 using external offsets shall have a rate of reduction for such offsets pursuant to subparagraph (c)(5)(C). New facilities initially totally permitted on or after January 7, 2005 using RTCs shall have no rate of reduction for such RTCs, provided that RTCs obtained have been adjusted according to paragraph (f)(1), as applicable. The Facility Permit for such facilities will require the Facility Permit holder to, at the commencement of each compliance year, hold RTCs equal to the amount of RTCs provided as offsets pursuant to Rule 2005.

(3) Increases to Allocations for permits issued for Clean Fuel adjustments pursuant to paragraph (c)(12), shall be added to each year's Allocation.

(4) During a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries, the current compliance year Non-tradable/Non-usable NOx RTCs held by electricity generating facilities as defined in Rule 2001(g)(1) that generate and distribute electricity to the grid system(s) affected by the State of Emergency may be used to offset their emissions after completely exhausting their own Tradable/Usable NOx RTCs.

If such a facility has completely exhausted their Non-tradable/Non-usable NOx RTCs, the owner or operator of the facility may apply for the use of the NOx RTCs in the Regional NSR Holding Account. The use of such RTCs in this Account shall be based on availability at the end of each quarter. The owner or operator of each ~~electrical~~electricity generating facility requesting NOx RTCs from the Regional NSR Holding Account shall submit a written request to the Executive Officer specifying the amount of RTCs needed and the basis for requesting the required amount.

The Executive Officer will determine the amount and distribution of the NOx RTCs from the Regional NSR Holding Account based on the requesting facility meeting the following criteria:

(i) The State of Emergency related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries, as declared by the Governor, was the direct cause of the excess emissions~~.~~;

(ii) The facility has been ordered to generate electricity in an increased amount and/or frequency due to the State of Emergency~~.~~;

(iii) The facility has adequately demonstrated their need for the specific amount of RTCs from the Regional NSR Holding Account~~.~~; and

(iv) The facility owner or operator has not sold any part of their RTC holdings for the subject compliance year.

If the total RTCs requested exceed the supply of RTCs in this Account, the RTCs will be distributed proportionately according to the offset needs of the facilities on a quarterly basis. These RTCs will be non-tradable, but usable to offset emissions.

(5) The Executive Officer will report to the Governing Board within 60 days of the end of the quarter in which a State of Emergency was declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries~~in the Basin~~. Included in this report will be, as applicable:

(i) the quantity of RTCs from the Regional NSR Holding Account that were distributed for compliance with the requirement to reconcile quarterly and annual emissions;

(ii) any adverse impacts that the State of Emergency is having on the RECLAIM program; and

(iii) any potential changes to the RECLAIM program that will be needed to help correct these impacts.

(g) High Employment/Low Emissions (HILO) Facility

The Executive Officer or designee will establish a HILO bank funded with the following maximum total annual emission Allocations:

(1) 91 tons per year of NO_X

(2) 91 tons per year of ~~So_X~~SO_X

(3) After January 1, 1997, new facilities may apply to the HILO bank in order to obtain non-tradable RTCs. Requests will be processed on a first-come, first-served basis, pending qualification.

(4) When credits are available, annual Allocations will be granted for the year of application and all subsequent years.

(5) HILO facilities receiving such Allocations from the HILO bank must verify their HILO status on an annual basis through their APEP report.

(6) Failure to qualify will result in all subsequent years' credits being returned to the HILO bank.

(7) Facilities failing to qualify for the HILO bank Allocations may reapply at any time during the next or subsequent compliance year when credits are available.

(h) Non-Tradable Allocation Credits

(1) Any existing RECLAIM facility with reported emissions pursuant to Rule 301 - Permit Fees, in either 1987, 1988, or 1993, greater than its starting Allocation, shall be assigned non-tradable credits for the first three years of the program which shall be determined according to the following methodology:

Non-tradable credit for NO_X and SO_X:

Year 1 = $(\Sigma [A \times B_1])$ - 1994 Allocation;

Where:

A	=	the throughput for each NO_X or SO_X source or process unit in the facility from the single maximum throughput year from 1987, 1988, or 1993; and
B_1	=	the applicable starting emission factor, as specified in Table 1 or Table 2.
Year 2	=	Year 1 non-tradable credits X 0.667
Year 3	=	Year 1 non-tradable credits X 0.333
Year 4 and subsequent years	=	Zero non-tradable credit.

(2) The use of non-tradable credits shall be subject to the following requirements:

(A) Non-tradable credits may only be used for an increase in throughput over that used to determine the facility's starting Allocation. Non-tradable credits may not be used for emissions increases associated with equipment modifications, change in feedstock or raw materials, or any other changes except increases in throughput. The Executive Officer or designee may impose Facility Permit conditions necessary to ensure compliance with this subparagraph.

(B) The use of activated non-tradable credits shall be subject to a non-tradable RTC mitigation fee, as specified in Rule 301 subdivision (n).

(C) In order to utilize non-tradable credits, the Facility Permit holder shall submit a request to the Executive Officer or designee in writing, including a demonstration that the use of the non-tradable credits complies with all requirements of this paragraph, pay any fees required pursuant to Rule 301 - Fees, and have received written approval from the Executive Officer or designee for their use. The Executive Officer or designee shall deny the request unless the Facility Permit holder demonstrates compliance with all requirements of this paragraph. The Executive Officer or designee shall, in writing, approve or deny the request within three business days of submittal of a complete request and notify the Facility Permit holder of the decision. If the request is denied, the Executive Officer or designee will refund the mitigation fee.

(D) In the event that a facility transfers any RTCs for the year in which non-tradable credits have been issued, the non-tradable credit Allocation shall be invalid, and is no longer available to the facility.

~~(i) RTC Reduction Exemption~~

~~(1) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraphs (f)(1)(A) with the exception of RTC holdings as of January 7, 2005 and thereafter in excess of the initial allocation. For the purposes of this rule, initial allocation refers to the RTCs issued by the District to a facility upon entering the RECLAIM program. The application shall~~

~~contain sufficient data to demonstrate to the satisfaction of the Executive Officer that the facility meets the following criteria:~~

~~(A)~~ ~~the facility has been in the program since the start of RECLAIM, or existed prior to 1994, but subsequently entered RECLAIM pursuant to Rule 2001 because facility emissions exceeded 4 tons per year;~~

~~(B)~~ ~~at least 99 percent of the facility's emissions reported for compliance year is from equipment not listed in Table 3 and the achieved emission rates for each and every piece of equipment at the facility is less than or equal to the 2000 (Tier I) Ending Emission Factor listed in Table 1 or the emission factor listed in Table 3, whichever is lower, for the corresponding equipment type;~~

~~(C)~~ ~~RTCs that were part of the total initial allocation for the facility have never been transferred or sold by the facility for year2007 or later; and~~

~~(D)~~ ~~the cumulative NOx compliance costs incurred by the facility up to the submittal date of the application as specified in paragraph (i)(3) to comply with the RECLAIM Allocation as required under Rule 2004(b) and (d)(1) exceed the compliance costs that otherwise would have occurred to meet and maintain emission limits specified in Table 1, for each and every piece of equipment at the facility. The compliance costs shall be based on the following parameters:~~

~~(i)~~ ~~cost of controlling emissions using the parameters and procedures for determining total direct and indirect capital investment and total annual costs as specified in the most recent edition of the Control Cost Manual published by the U.S. EPA Office of Air Quality and Planning Standards, excluding control costs for any equipment listed in Table 3, if any;~~

~~(ii)~~ ~~realized and anticipated revenues and expenditures of the Facility Permit holder resulting from buying and selling any RTCs that are or were held by the facility where the contract of sale or purchase was executed prior to the date of application for exemption pursuant to paragraph (i)(1);~~

~~(iii) costs associated with compliance with the New Source Review provisions of Rule 2005, Rule 2012(c), or other applicable state or federal requirements shall not be included;~~

~~(iv) costs that result only in improving process efficiency or product quality, costs of projects that were initiated before the date the facility was subject to RECLAIM requirements, or legal costs or any other costs that do not directly reduce NOx emissions shall not be included; and~~

~~(v) any cost savings that resulted in implementing any NOx emissions strategy, such as fuel savings, increased production or sale; or~~

~~(2) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraph (f)(1)(A) for the initial allocations portion of a facility's RTC holdings provided that the facility meets all of the following:~~

~~(A) The facility's starting and year 2000 Allocations were calculated using the same emission factors that are equal to or lower than the 2000 (Tier 1) emission factors listed in Table 1;~~

~~(B) Emission rate achieved for each source at the facility is less than or equal to the emission factors listed in Table 3 for the corresponding equipment type; and~~

~~(C) RTCs for 2007 or later compliance years for the facility have never been transferred or sold.~~

~~(3) A facility shall submit the applications specified pursuant to paragraphs (i)(1) or (i)(2) no later than July 7, 2005, pay the appropriate evaluation fee pursuant to Rule 306, and accept enforceable permit conditions to ensure compliance with the provisions of this subdivision, in order for the Executive Officer to approve the exemption. If approved, the facility's initial RTC allocation shall be designated as non-tradable and additional RTCs purchased above the initial allocation shall be subject to the RTC adjustments specified in subparagraph (f)(1)(A), as appropriate. The Executive Officer shall deny an application that is not filed within the time periods specified in this paragraph, lacks any information specified under paragraph (i)(7), or fails to demonstrate that it meets the requirements in paragraphs (i)(1) or (i)(2).~~

~~(4) Upon approval the exemption shall:~~

~~(A) be limited to the adjustment factors specified in subparagraph (f)(1)(A);~~

~~(B) begin the next compliance year following the exemption approval; and~~

~~(C) not apply to reductions resulting from future periodic BARCT review.~~

~~(5) RTC adjustments exempted pursuant to this subdivision shall be distributed proportionally among the remainder of the RTC holders and implemented two years from the compliance year of the applicable exemption and are subject to applicable paragraph (f)(1) provisions. Public notification of the distributed reductions shall occur at least one year prior to implementation.~~

~~(6) A Facility Permit holder has the right to appeal the denial of the exemption application to the Hearing Board in the same manner as a permit denial as specified in Health and Safety Code Section 42302.~~

~~(7) An application submitted to request an exemption from the RTCs reduction pursuant to paragraphs (i)(1) or (i)(2) shall include the following information.~~

~~(A) Detailed description of each project and itemized listing of how it relates to meeting the RECLAIM reduction requirements;~~

~~(B) Date of start and completion of each project listed in (A);~~

~~(C) Detailed calculations or emissions data demonstrating NOx emission reductions resulting from each project or combination of projects directly resulting in reductions. The emission levels achieved shall be based on actual CEMS data or source tests results;~~

~~(D) Itemized revenue and expenditures for each RTC trading activity since participation in the RECLAIM program;~~

~~(E) Itemized costs for each project and corresponding receipts or other equivalent documentation as approved by the Executive Officer for such expenditures; and~~

~~(F) Cost savings resulting from each project(s) (e.g. fuel savings, improved productivity, increased sales, etc.) and documentation of the values of such savings.~~

~~(8) A facility qualifying for exemption shall report as part of its Annual Permit Emission Program (APEP) report, submitted pursuant to Rule 2004(b)(4), whether or not emissions from equipment listed in Tables 3, if any, remain~~

~~less than or equal to 1 percent of the total facility emissions on an annual basis for the duration of the exemption. If the emissions exceed 1 percent, the facility shall be in violation of the rule for each and every day of the compliance year and the Executive Officer shall reduce the facility's initial allocation for the next compliance year to the emissions level specified for that year pursuant to subparagraph (f)(1)(A).~~

~~(9) A facility applying for exemption shall have 1 percent of its initial allocations subject to the requirements pursuant to subparagraph (f)(1)(A).~~

~~(10) Non-tradable RTC allocations designated pursuant to paragraph (i)(3) shall become tradable in the event the facility permanently ceases to operate.~~

(i) Facility and Equipment Shutdowns

(1) Starting (*date of amendment*) the highest ranking official of any facility listed in Table 7 or 8 selling any infinite year block (IYB) RTCs shall provide the Executive Officer a written statement that there is no current intent~~*ion*~~ to shut down the facility within the next five years. For the purpose of this rule, IYB refer to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

(2) On or after [*2 years after date of amendment*], ~~*A*~~any Facility Permit Holder of a facility listed in Table 7 or 8 permanently shutting down ~~*some or all*~~one or more pieces of equipment with emissions greater than or equal to 25 percent of the facility's total NOx emissions for any quarter within the previous 2 compliance years shall surrender:

(A) NOx RTCs as determined under paragraph (i)(3) to the District for retirement from the RECLAIM Program; and

(B) the permit(s) for the equipment that is shutdown.

Equipment shall be deemed permanently shut down and subject to the RTC and permit surrender requirements of this paragraph if it is non-operational for a period of two consecutive years or longer, unless the Executive Officer determines, based on evidence provided by the operator, that the subject equipment is used in a cyclical operation with a cyclic period of two or more years, or that the equipment's period of non-operation extends beyond two years due to circumstances that are beyond the control of the operator and otherwise the equipment would have been fully operational.

(3) The NOx RTCs to be surrendered as specified in paragraph (i)(2) shall include those valid for all compliance years starting from the compliance year after the shutdown occurs and be equal to the NOx Allocations issued by the District to the facility multiplied by the maximum quarterly ratio in the previous 2 years. For the purposes of this rule, each quarterly ratio shall be calculated as follows:

$$Quarterly\ Ratio = \frac{Quarterly\ NOx\ emissions\ from\ the\ shutdown\ equipment}{Total\ facility\ \cancel{certified}\ quarterly\ NOx\ emissions\ for\ the\ same\ quarter}$$

(4) The requirements specified in paragraphs (i)(2) and (i)(3) shall not apply to shutdown equipment for which the equipment's operational capacity is replaced by new or existing equipment serving the same functional needs at the same facility or another facility under common control.

(5) Notwithstanding the requirements of Rule 204, the Executive Officer shall notify the Facility Permit Holder 60 days prior to re-issuing the Facility Permit to reflect removal of the shutdown equipment from the Facility Permit.

Table 1

RECLAIM NO_X Emission Factors

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Afterburner (Direct Flame and Catalytic)	Natural Gas	mmcf	130.000	39.000
Afterburner (Direct Flame and Catalytic)	LPG, Propane, Butane	1000 Gal	RV	3.840
Afterburner (Direct Flame and Catalytic)	Diesel	1000 Gal	RV	5.700
Agr Chem-Nitric Acid	Process-Absrbr Tailgas/Nw	tons pure acid produced	RV	1.440
Agricultural Chem - Ammonia	Process	tons produced	RV	1.650
Air Ground Turbines	Air Ground Turbines	(unknown process units)	RV	1.860
Ammonia Plant	Neutralizer Fert, Ammon Nit	tons produced	RV	2.500
Asphalt Heater, Concrete	Natural Gas	mmcf	130.000	65.000
Asphalt Heater, Concrete	Fuel Oil	1000 gals	RV	9.500
Asphalt Heater, Concrete	LPG	1000 gals	RV	6.400
Boiler, Heater R1109 (Petr Refin)	Natural Gas	mmbtu	0.100	0.030
Boiler, Heater R1109 (Petr Refin)	Fuel Oil	mmbtu	0.100	0.030
Boiler, Heater R1146 (Petr Refin)	Natural Gas	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Fuel Oil	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Refinery Gas	mmbtu	0.045	0.045
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Natural Gas	mmcf	49.180	47.570
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	LPG, Propane, Butane	1000 gals	4.400	4.260
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Diesel Light Dist. (0.05% S)	1000 gals	6.420	6.210
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Refinery Gas	mmcf	51.520	49.840
Boilers, Heaters, Steam Gens	Bituminous Coal	tons burned	RV	4.800
Boiler, Heater, Steam Gen (Rule 1146.1)	Natural Gas	mmcf	130.000	39.460
Boiler, Heater, Steam Gen (Rule 1146.1)	Refinery Gas	mmcf	RV	41.340

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boiler, Heater, Steam Gen (Rule 1146.1)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (Rule 1146.1)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater, Steam Gen (Rule 1146)	Natural Gas	mmcf	47.750	47.750
Boiler, Heater, Steam Gen (Rule 1146)	Refinery Gas	mmcf	50.030	50.030
Boiler, Heater, Steam Gen (Rule 1146)	LPG, Propane, Butane	1000 gallons	4.280	4.280
Boiler, Heater, Steam Gen (Rule 1146)	Diesel Light Dist (0.05%)	1000 gallons	6.230	6.230
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Natural Gas	mmcf	RV	47.750
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Refinery Gas	mmcf	RV	50.030
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	4.280
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	6.230
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Natural Gas	mmcf	RV	39.460
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Refinery Gas	mmcf	RV	41.340
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater R1109 (Petr Refin)	Refinery Gas	mmbtu	0.100	0.030
Boilers, Heaters, Steam Gens, (Petr Refin)	Natural Gas	mmcf	105.000	31.500
Boilers, Heaters, Steam Gens, (Petr Refin)	Refinery Gas	mmcf	110.000	33.000
Boilers, Heaters, Steam Gens, Unpermitted	Natural Gas	mmcf	130.000	32.500
Boilers, Heaters, Steam Gens, Unpermitted	LPG, Propane, Butane	1000 gallons	RV	3.200
Boilers, Heaters, Steam Gens ****	Natural Gas	mmcf	38.460	38.460

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boilers, Heaters, Steam Gens ****	Refinery Gas	mmbtu	0.035	0.035
Boilers, Heaters, Steam Gens ****	LPG, Propane, Butane	1000 gallons	3.55	3.55
Boilers, Heaters, Steam Gens ****	Diesel Light Dist (0.05%), Fuel Oil No. 2	mmbtu	0.03847	0.03847
Boilers, Heaters, Steam Gens, Unpermitted	Diesel Light Dist (0.05%)	1000 gallons	RV	4.750
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	1.660
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	2.090
Cement Kilns	Natural Gas	mmcf	130.000	19.500
Cement Kilns	Diesel Light Dist. (0.05% S)	1000 gals	RV	2.850
Cement Kilns	Kilns-Dry Process	tons cement produced	RV	0.750
Cement Kilns	Bituminous Coal	tons burned	RV	4.800
Cement Kilns	Tons Clinker	tons clinker	RV	2.73***
Ceramic and Brick Kilns (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Ceramic and Brick Kilns (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Ceramic and Brick Kilns (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Ceramic Clay Mfg	Drying	tons input to process	RV	1.114
CO Boiler	Refinery Gas	mmbtu		0.030
Cogen, Industr	Coke	tons burned	RV	3.682
Electric Generation, Commercial Institutional Boiler	Distillate Oil	1000 gallons	6.420	6.210
Composite Internal Combustion	Waste Fuel Oil	1000 gals burned	RV	31.340
Curing and Drying Ovens	Natural Gas	mmcf	130.000	32.500

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Curing and Drying Ovens	LPG, Propane, Butane	1000 gals	RV	3.200
Delacquering Furnace	Natural Gas	mmcf	182.2***	182.2***
Fiberglass	Textile-Type Fibr	tons of material processed	RV	1.860
Fluid Catalytic Cracking Unit	Fresh Feed	1000 BBLS fresh feed	RV	RV*0.3 ***
Fluid Catalytic Cracking Unit with Urea Injection	Fresh Feed	1000 BBLS fresh feed	RV	(RV*0.3) / (1-control efficiency) ***
Fugitive Emission	Not Classified	tons product	RV	0.087
Furnace Process	Carbon Black	tons produced	RV	38.850
Furnace Suppressor	Furnace Suppressor	unknown	RV	0.800
Glass Fiber Furnace	Mineral Products	tons product produced	RV	4.000
Glass Melting Furnace	Flat Glass	tons of glass pulled	RV	4.000
Glass Melting Furnace	Tableware Glass	tons of glass pulled	RV	5.680
Glass Melting Furnaces	Container Glass	tons of glass produced	4.000	1.2***
ICEs****	All Fuels		Equivalent to permitted BACT limit	Equivalent to permitted BACT limit
ICEs, Permitted (Rule 1110.1 and 1110.2)	Natural Gas	mmcf	2192.450	217.360
ICEs Permitted (Rule 1110.2)	Natural Gas	mmcf	RV	217.360
ICEs, Permitted (Rule 1110.1 and 1110.2)	LPG, Propane, Butane	1000 gals	RV	19.460
ICEs, Permitted (Rule 1110.1 and 1110.2)	Gasoline	1000 gals	RV	20.130
ICEs, Permitted (Rule 1110.1 and 1110.2)	Diesel Oil	1000 gals	RV	31.340
ICEs, Exempted per Rule 1110.2	All Fuels		RV	RV
ICEs, Exempted per Rule 1110.2 and subject to Rule 1110.1	All Fuels		RV	RV
ICEs, Unpermitted	All Fuels		RV	RV
In Process Fuel	Coke	tons burned	RV	24.593
Incinerators	Natural Gas	mmcf	130.000	104.000
Industrial	Propane	1000 gallons	RV	20.890
Industrial	Gasoline	1000 gallons	RV	21.620

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Industrial	Dist.Oil/Diesel	1000 gallons	RV	33.650
Inorganic Chemicals, H2SO4 Chamber	General	tons pure acid produced	RV	0.266
Inorganic Chemicals, H2SO4 Contact	Absrbr 98.0% Conv	tons 100% H2S04	RV	0.376
Iron/Steel Foundry	Steel Foundry, Elec Arc Furn	tons metal processed	RV	0.045
Metal Heat Treating Furnace	Natural Gas	mmcf	130.000	104.000
Metal Heat Treating Furnace	Diesel Light Distillate (.05%)	1000 gallons	RV	15.200
Metal Heat Treating Furnace	LPG	1000 gallons	RV	10.240
Metal Forging Furnace (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Metal Forging Furnace (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Metal Forging Furnace (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Metal Melting Furnaces	Natural Gas	mmcf	130.000	65.000
Metal Melting Furnaces	LPG, Propane, Butane	1000 gals	RV	6.400
Miscellaneous		bbls-processed	RV	1.240
Natural Gas Production	Not Classified	mmcf gas	RV	6.320
Nonmetallic Mineral	Sand/Gravel	tons product	RV	0.030
NSPS	Refinery Gas	mmbtu	RV	0.030
Other BACT Heater (24F-1)	Natural Gas	mmcf	RV	RV
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV
Ovens, Kilns, Calciners, Dryers, Furnaces**	Natural Gas	mmcf	130.000	65.000
Ovens, Kilns, Calciners, Dryers, Furnaces**	Diesel Light Dist. (0.05% S)	1000 gals	RV	9.500
Paint Mfg, Solvent Loss	Mixing/Blending	tons solvent	RV	45.600
Petroleum Refining	Asphalt Blowing	tons of asphalt produced	RV	45.600
Petroleum Refining, Calciner	Petroleum Coke	Calcined Coke	RV	0.971***
Plastics Prodn	Polyester Resins	tons product	RV	106.500
Pot Furnace	Lead Battery	lbs Niter	0.077***	0.062***
Process Specific	ID# 012183	(unknown process units)	RV	240.000
Process Specific	SCC 30500311	tons produced	RV	0.140

* RV = Reported Value

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Process Specific	ID 14944	(unknown process units)	RV	0.512
SCC 39090003			RV	170.400
Sec. Aluminum	Sweating Furnace	tons produced	RV	0.300
Sec. Aluminum	Smelting Furnace	tons metal produced	RV	0.323
Sec. Aluminum	Annealing Furnace	mmcf	130.000	65.000
Sec. Aluminum	Boring Dryer	tons produced	RV	0.057
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.110
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.060
Sodium Silicate Furnace	Water Glass	Tons Glass Pulled	RV	6.400
Steel Hot Plate Furnace	Natural Gas	mmcf	213.000	106.500
Steel Hot Plate Furnace	Diesel Light Distillate (.05%)	1000 gallons	31.131	10.486
Steel Hot Plate Furnace	LPG, Propane, Butane	1000 gallons	20.970	10.486
Surface Coal Mine	Haul Road	tons coal	RV	62.140
Tail Gas Unit		hours of operation	RV	RV
Turbines	Butane	1000 Gallons	RV	5.700
Turbines	Diesel Oil	1000 gals	RV	8.814
Turbines	Refinery Gas	mmcf	RV	62.275
Turbines	Natural Gas	mmcf	RV	61.450
Turbines (micro-)	Natural Gas	mmcf	54.4	54.4
Turbines - Peaking Unit	Natural Gas	mmcf	RV	RV
Turbines - Peaking Unit	Dist. Oil/Diesel	1000 gallons	RV	RV
Utility Boiler	Digester/Landfill Gas	mmcf	52.350	10.080
Turbine	Natural Gas	mmcf	RV	61.450
Turbine	Fuel Oil	1000 gallons	RV	8.810
Turbine	Dist.Oil/Diesel	1000 gallons	RV	3.000
Utility Boiler Burbank	Natural Gas	mmcf	148.670	17.200
Utility Boiler Burbank	Residual Oil	1000 gallons	20.170	2.330
Utility Boiler, Glendale	Natural Gas	mmcf	140.430	16.000
Utility Boiler, Glendale	Residual Oil	1000 gallons	20.160	2.290
Utility Boiler, LADWP	Natural Gas	mmcf	86.560	15.830
Utility Boiler, LADWP	Residual Oil	1000 gallons	12.370	2.260
Utility Boiler, LADWP	Digester Gas	mmcf	52.350	10.080
Utility Boiler, LADWP	Landfill Gas	mmcf	37.760	6.910
Utility Boiler, Pasadena	Natural Gas	mmcf	195.640	18.500
Utility Boiler, Pasadena	Residual Oil	1000 gallons	28.290	2.670
Utility Boiler, SCE	Natural Gas	mmcf	74.860	15.600
Utility Boiler, SCE	Residual Oil	1000 gallons	10.750	2.240

* RV = Reported Value

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Table 2

RECLAIM SO_x Emission Factors

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Air Blown Asphalt		hours of operation	RV	RV
Asphalt Concrete	Cold Ag Handling	tons produced	RV	0.032
Calciner	Petroleum Coke	Calcined Coke	RV	0.000
Catalyst Regeneration		hours of operation	RV	RV
Cement Kiln	Distillate Oil	1000 gallons	RV	RV
Cement Mfg	Kilns, Dry Process	tons produced	RV	RV
Claus Unit		pounds	RV	RV
Cogen	Coke	pounds per ton	RV	RV
Non Fuel Use		hours of operation	RV	RV
External Combustion Equipment / Incinerator	Natural Gas	mmcf	RV	0.830
External Combustion Equip/Incinerator	LPG, Propane, Butane	1000 gallons	RV	4.600
External Combustion Equip/Incinerator	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	5.600
External Combustion Equip/Incinerator	Residual Oil	1000 gallons	8.00	6.400
External Combustion Equip/Incinerator	Refinery Gas	mmcf	RV	6.760
Fiberglass	Recuperative Furn, Textile-Type Fiber	tons produced	RV	2.145
Fluid Catalytic Cracking Units		1000 bbls refinery feed	RV	13.700
Glass Mfg, Forming/Fin	Container Glass		RV	RV
Grain Milling	Flour Mill	tons Grain Processed	RV	RV
ICEs	Natural Gas	mmcf	RV	0.600
ICEs	LPG, Propane, Butane	1000 gallons	RV	0.350
ICEs	Gasoline	1000 gallons	RV	4.240
ICEs	Diesel Oil	1000 gallons	6.24	4.990
Industrial	Cogeneration, Bituminous Coal	tons produced	RV	RV
Industrial (scc 10200804)	Cogeneration, Coke	tons produced	RV	RV
Inorganic Chemcals	General, H2SO4 Chamber	tons produced	RV	RV
Inorganic Chemcals	Absrbr 98.0% Conv, H2SO4 Contact	tons produced	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Inprocess Fuel	Cement Kiln/Dryer, Bituminous Coal	tons produced	RV	RV
Iron/Steel Foundry	Cupola, Gray Iron Foundry	tons produced	RV	0.720
Melting Furnace, Container Glass		tons produced	RV	RV
Mericher Alkyd Feed		hours of operation	RV	RV
Miscellaneous	Not Classified	tons produced	RV	0.080
Miscellaneous	Not Classified	tons produced	RV	0.399
Natural Gas Production	Not Classified	mmcf	RV	527.641
Organic Chemical (scc 30100601)		tons produced	RV	RV
Petroleum Refining (scc30600602)	Column Condenser		RV	1.557
Petroleum Refining (scc30600603)	Column Condenser		RV	1.176
Refinery Process Heaters	LPG fired	1000 gal	RV	2.259
Pot Furnace	Lead Battery	lbs Sulfur	0.133***	0.106***
Sec. Lead	Reverberatory, Smelting Furnace	tons produced	RV	RV
Sec. Lead	Smelting Furnace, Fugitiv	tons produced	RV	0.648
Sour Water Oxidizer		hours of operation	RV	RV
Sulfur Loading		1000 bbls	RV	RV
Sour Water Oxidizer		1000 bbls fresh feed	RV	RV
Sour Water Coker		1000 bbls fresh feed	RV	RV
Sodium Silicate Furnace		tons of glass pulled	RV	RV
Sulfur Plant		hours of operation	RV	RV
Tail gas unit		hours of operation	RV	RV
Turbines	Refinery Gas	mmcf	RV	6.760
Turbines	Natural Gas	mmcf	RV	0.600
Turbines	Diesel Oil	1000 gal	6.24	0.080
Turbines	Residual Oil	1000 gallons	8.00	0.090
Utility Boilers	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	0.080
Utility Boilers	Residual Oil	1000 gallons	8.00	0.090
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Table 3

RECLAIM NO_X 2011 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Asphalt Heater, Concrete	0.036 lb/mmbtu (30 ppm)
Boiler, Heater R1109 (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boilers, Heaters, Steam Gens, (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boiler, Heater, Steam Gen (Rule 1146.1) 2-20 mmbtu/hr	0.015 lb/mmbtu (12 ppm)
Boiler, Heater, Steam Gen (Rule 1146) >20 mmbtu/hr	0.010 lb/mmbtu (9 ppm)
CO Boiler	85% Reduction
Delacquering Furnace	0.036 lb/mmbtu (30 ppm)
Fluid Catalytic Cracking Unit	85% Reduction
Iron/Steel Foundry	0.055 lb/mmbtu (45 ppm)
Metal Heat Treating Furnace	0.055 lb/mmbtu (45 ppm)
Metal Forging Furnace (Preheated Combustion Air)	0.055 lb/mmbtu (45 ppm)
Metal Melting Furnaces	0.055 lb/mmbtu (45 ppm)
Other Heater (24F-1)	0.036 lb/mmbtu (30 ppm)
Ovens, Kilns, Calciners, Dryers, Furnaces	0.036 lb/mmbtu (30 ppm)
Petroleum Refining, Calciner	0.036 lb/mmbtu (30 ppm)
Sec. Aluminum	0.055 lb/mmbtu (45 ppm)
Sec. Lead	0.055 lb/mmbtu (45 ppm)
Steel Hot Plate Furnace	0.055 lb/mmbtu (45 ppm)
Utility Boiler	0.008 lb/mmbtu (7 ppm)

Table 4
RECLAIM SOx Tier III Emission Standards

Basic Equipment	BARCT Emission Standard
Calciner, Petroleum Coke	10 ppmv (0.11 lbs/ton coke)
Cement Kiln	5 ppmv (0.04 lbs/ton clinker)
Coal-Fired Boiler	5 ppmv (95% reduction)
Container Glass Melting Furnace	5 ppmv (0.03 lbs/ton glass)
Diesel Combustion	15 ppm~~v~~ by weight as required under Rule 431.2
Fluid Catalytic Cracking Unit	5 ppmv (3.25 lbs/thousand barrels feed)
Refinery Boiler/Heater	40 ppmv (6.76 lbs/mmscf~~t~~)
Sulfur Recovery Units/Tail Gas	5 ppmv for combusted tail gas (5.28 lbs/hour)
Sulfuric Acid Manufacturing	10 ppmv (0.14 lbs/ton acid produced)

Table 5
List of SOx RECLAIM Facilities Referenced in Sub~~P~~paragraphs (f)(1)(M) and (f)(1)(O)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES HUNTINGTON BEACH, LLC*	115389
AIR LIQUIDE LARGE INDUSTRIES U.S., LP	148236
ANHEUSER-BUSCH INC., (LA BREWERY)	16642
CALMAT CO	119104
CENCO REFINING CO	800373
EDGINGTON OIL COMPANY	800264
EQUILON ENTER. LLC, SHELL OIL PROD. US	800372
EXIDE TECHNOLOGIES	124838
INEOS POLYPROPYLENE LLC	124808
KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	21887
LUNDAY-THAGARD COMPANY	800080
OWENS CORNING ROOFING AND ASPHALT, LLC	35302
PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	45746
PARAMOUNT PETR CORP*	800183
QUEMETCO INC	8547
RIVERSIDE CEMENT CO	800182
TECHALLOY CO., INC.	14944
TESORO REFINING AND MARKETING CO*	151798
THE PQ CORP	11435
US GYPSUM CO	12185
WEST NEWPORT OIL CO	42775

* SOx RECLAIM facilities that have RTC Holdings larger than initial allocations as of August 29, 2009.

Table 6

RECLAIM NO_x 2022 Ending Emission Factors

Nitrogen Oxides Basic Equipment	**BARCT Emission Factor**
Boiler, Heater R1109 (Petr Refin) >40 mmbtu/hr	2 ppm
Cement Kilns	0.5 lbs per ton clinker
Fluid Catalytic Cracking Unit	2 ppm
Gas Turbines	2 ppm
Glass Melting Furnaces – Container Glass	80% reduction (0.24 lb/ton glass produced)
ICEs, Permitted (Rule 1110.2) (Non-OCS)	11 ppm @15%O_2 0.041 lb/MMBTU 43.05 lb/mmcf
Metal Heat Treating Furnace >150 mmbtu/hr	0.011 lb/mmbtu (9 ppm)
Petroleum Refining, Calciner	10 ppm
Sodium Silicate Furnace	80% reduction (1.28 lb/ton glass pulled)
SRU/Tail Gas Unit	95% reduction 2ppm

Table 7

List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(B)

FACILITY PERMIT HOLDER	AQMD ID NO.
CHEVRON PRODUCTS CO.	800030
EXXONMOBIL OIL CORPORATION	800089
PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	171107
PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	171109
TESORO REF & MKTG CO LLC,CALCINER	174591
TESORO REFINING & MARKETING CO, LLC	174655
TESORO REFINING AND MARKETING CO, LLC	151798
TESORO REFINING AND MARKETING CO, LLC	800436
ULTRAMAR INC	800026
NOx RTC holders not designated as Facility Permit Holders as of September 22, 2015, except any NOx RTC holders listed in Table 8	Multiple

Table 8

List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(C)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES ALAMITOS, LLC	115394
AES HUNTINGTON BEACH, LLC	115389
AES REDONDO BEACH, LLC	115536
BERRY PETROLEUM COMPANY	119907
BETA OFFSHORE	166073
BICENT (CALIFORNIA) MALBURG LLC	155474
BORAL ROOFING LLC	1073
BURBANK CITY, BURBANK WATER & POWER	25638
BURBANK CITY,BURBANK WATER & POWER,SCPPA	128243
CALIFORNIA PORTLAND CEMENT CO	800181
CALIFORNIA STEEL INDUSTRIES INC	46268
CANYON POWER PLANT	153992
CPV SENTINEL LLC	152707
DISNEYLAND RESORT	800189
EDISON MISSION HUNTINGTON BEACH, LLC	167432
EL SEGUNDO POWER, LLC	115663
EXIDE TECHNOLOGIES	124838
GENERAL ELECTRIC COMPANY	700126
HARBOR COGENERATION CO, LLC	156741
INLAND EMPIRE ENERGY CENTER, LLC	129816
LA CITY, DWP HAYNES GENERATING STATION	800074
LA CITY, DWP SCATTERGOOD GENERATING STN	800075
LA CITY, DWP VALLEY GENERATING STATION	800193
LONG BEACH GENERATION, LLC	115314
NEW- INDY ONTARIO, LLC	172005
NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	115315
OWENS-BROCKWAY GLASS CONTAINER INC	7427
OXY USA INC	169754
PACIFIC CLAY PRODUCTS INC	17953
PARAMOUNT PETR CORP	800183
PASADENA CITY, DWP	800168
PQ CORPORATION	11435
QUEMETCO INC	8547
SAN DIEGO GAS & ELECTRIC	4242
SNOW SUMMIT INC	43201
SO CAL EDISON CO	4477
SO CAL GAS CO	800128
SO CAL GAS CO	800127
SO CAL GAS CO	5973
SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	8582
SOLVAY USA, INC.	114801

FACILITY PERMIT HOLDER	AQMD ID NO.
SOUTHERN CALIFORNIA EDISON	160437
TABC, INC	3968
TAMCO	18931
US GOVT, NAVY DEPT LB SHIPYARD	800153
WALNUT CREEK ENERGY, LLC	146536
WHEELABRATOR NORWALK ENERGY CO INC	51620
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299

Table 9
List of NOx RECLAIM Facilities for the Regional NSR Holding Account with Balances (in lbs)

~~FACILITY PERMIT HOLDER~~	~~AQMD ID NO.~~	~~2016~~	~~2017~~	~~2018~~	~~2019~~	~~2020~~	~~2021~~	~~2022~~	~~2023+~~
~~BICENT (CALIFORNIA) MALBURG LLC~~	~~155474~~	~~0~~	~~7,461~~	~~7,461~~	~~11,192~~	~~14,922~~	~~18,653~~	~~22,383~~	~~26,114~~
~~BURBANK CITY,BURBANK WATER & POWER,SCPPA~~	~~128243~~	~~0~~	~~13,610~~	~~13,610~~	~~20,415~~	~~27,220~~	~~34,025~~	~~40,830~~	~~47,635~~
~~CANYON POWER PLANT~~	~~153992~~	~~0~~	~~11,664~~	~~11,664~~	~~17,496~~	~~23,328~~	~~29,160~~	~~34,992~~	~~40,824~~
~~CPV SENTINEL LLC~~	~~152707~~	~~0~~	~~33,459~~	~~33,459~~	~~50,188~~	~~66,918~~	~~83,647~~	~~100,377~~	~~117,106~~
~~GENERAL ELECTRIC COMPANY/INLAND EMPIRE ENERGY CENTER, LLC/~~	~~700126/ 129816~~	~~0~~	~~31,471~~	~~31,471~~	~~47,207~~	~~62,942~~	~~78,678~~	~~94,413~~	~~110,148~~
~~LONG BEACH GENERATION, LLC~~	~~115314~~	~~0~~	~~11,997~~	~~11,997~~	~~17,996~~	~~23,994~~	~~29,993~~	~~35,991~~	~~41,990~~
~~SOUTHERN CALIFORNIA EDISON~~	~~160437~~	~~0~~	~~40,217~~	~~40,217~~	~~60,326~~	~~80,435~~	~~100,543~~	~~120,652~~	~~140,761~~
~~WALNUT CREEK ENERGY, LLC~~	~~146536~~	~~0~~	~~15,962~~	~~15,961~~	~~23,942~~	~~31,923~~	~~39,904~~	~~47,885~~	~~55,866~~
~~WILDFLOWER ENERGY LP/INDIGO GEN., LLC~~	~~127299~~	~~0~~	~~7,009~~	~~7,009~~	~~10,514~~	~~14,018~~	~~17,523~~	~~21,027~~	~~24,532~~

FACILITY PERMIT HOLDER	AQMD ID NO.	2016		2017		2018		2019		2020		2021		2022		2023+	
		Dec 2016	Jun 2017	Dec 2017	Jun 2018	Dec 2018	Jun 2019	Dec 2019	Jun 2020	Dec 2020	Jun 2021	Dec 2021	Jun 2022	Dec 2022	Jun 2023	Dec 2023+	Jun 2023+
BICENT (CALIFORNIA) MALBURG LLC	155474	0	0	3,735	3,734	3,735	3,734	5,588	5,588	7,469	7,469	9,323	9,323	11,204	11,203	13,057	13,057
BURBANK CITY, BURBANK WATER & POWER, SCPPA	128243	0	0	3,232	10,392	3,232	10,392	4,836	15,551	6,464	20,784	8,068	25,943	9,695	31,177	11,300	36,335
CANYON POWER PLANT	153992	0	0	6,543	5,133	6,543	5,133	9,792	7,680	13,087	10,265	16,335	12,813	19,630	15,398	22,878	17,946
CPV CENTINEL LLC	152707	0	0	19,430	14,063	19,430	14,063	29,075	21,044	38,860	28,126	48,505	35,107	58,290	42,190	67,935	49,171
GENERAL ELECTRIC COMPANY/INLAND EMPIRE ENERGY CENTER	700126/ 129816	0	0	18,262	13,242	18,262	13,242	27,327	19,815	36,524	26,483	45,589	33,056	54,785	39,725	63,851	46,298
LONG BEACH GENERATION, LLC	115314	0	0	0	12,010	0	12,010	0	17,971	0	24,019	0	29,981	0	36,029	0	41,990
SOUTHERN CALIFORNIA EDISON	160437	0	0	26,647	13,612	26,647	13,612	39,874	20,369	53,293	27,225	66,521	33,982	79,940	40,837	93,167	47,594
WALNUT CREEK ENERGY, LLC	146536	0	0	7,434	8,544	7,434	8,544	11,124	12,786	14,867	17,089	18,558	21,330	22,301	25,633	25,991	29,874
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299	0	0	0	7,016	0	7,016	0	10,499	0	14,033	0	17,516	0	21,049	0	24,532

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended May 10, 1996)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended April 9, 1999)
(Amended April 20, 2001)(Amended May 6, 2005)(Amended June 3, 2011)
(Amended December 4, 2015)

PROPOSED AMENDED RULE 2005. NEW SOURCE REVIEW FOR RECLAIM

(a) Purpose

This rule sets forth pre-construction review requirements for new facilities subject to the requirements of the RECLAIM program, for modifications to RECLAIM facilities, and for facilities which increase their allocation to a level greater than their starting Allocation plus non-tradable credits. The purpose of this rule is to ensure that the operation of such facilities does not interfere with progress in attainment of the National Ambient Air Quality Standards, and that future economic growth in the South Coast Air Basin is not unnecessarily restricted.

(b) Requirements for New or Relocated RECLAIM Facilities

(1) The Executive Officer shall not approve the application for a Facility Permit to authorize construction or installation of a new or relocated facility unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to every emission source located at the facility; and

(B) the operation of any emission source located at the new or relocated facility will not cause a violation nor make significantly worse an existing violation of the state or national ambient air quality standard at any receptor location in the District for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve the application for a Facility Permit authorizing operation of a new or relocated facility, unless the applicant demonstrates that:

(A) the facility holds sufficient RTCs, including any RTCs from Table 9 in Rule 2002, to offset the total facility emissions for the first year of operation, at a 1-to-1 ratio; and

(B) the RTCs procured to comply with the requirements of subparagraph (b)(2)(A) were obtained pursuant to the requirements of subdivision (e), and

(C) the total facility emissions determined to comply with the requirements of subparagraph (b)(2)(A) shall also include ship emissions directly associated with activities at stationary sources subject to this rule as follows:

(i) all emissions from ships during the loading and unloading of cargo and while at berth where the cargo is loaded or unloaded; and

(ii) non-propulsion ship emissions within coastal waters under District jurisdiction.

(c) Requirements for Existing RECLAIM Facilities, Modification to New RECLAIM Facilities, Facilities which Undergo a Change of Operator, or Facilities which Increase an Annual Allocation to a Level Greater Than the Facility's Starting Allocation Plus Non-tradable Credits.

(1) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to the source; and

(B) the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize operation of the new or modified source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that the facility holds sufficient RTCs to offset the annual emission increase for the first year of operation at a 1-to-1 ratio.

(3) The Executive Officer shall not approve an application for Change of Operator for a Facility Permit unless the applicant demonstrates that the facility holds sufficient RTCs for the compliance year in which the change of operator permit is issued. Credits must be held in an amount equal to:

(A) The annual Allocation initially issued to the original Facility Permit holder for existing facility as defined in Rule 2000 for the same compliance year, in which the change of operator permit is issued, multiplied, where applicable, by the Tradable/Usable RTC Adjustment Factor for the same compliance year as listed in Rule 2002(f)(1)(A); or

(B) The sum of annual RECLAIM pollutants from all the sources located at the facility. The amount of annual RECLAIM pollutants for each source shall be calculated by the maximum hourly potential to emit, over an operating schedule of 24 hours per day and 365 days per year, or shall be based on a permit condition limiting the source's emission.

(4) The Executive Officer shall not approve an application to increase an annual Allocation to a level greater than the facility's starting Allocation plus non-tradable credits, unless the applicant demonstrates that:

(A) each source which creates an emission increase as defined in subdivision (d) will:

(i) apply Best Available Control Technology;

(ii) not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A; and

(B) the facility holds sufficient RTCs acquired pursuant to subdivision (e) to offset the annual increase in the facility's starting Allocation plus non-tradable credits at a 1-to-1 ratio for a minimum of one year.

(d) Emission Increase

An increase in emissions occurs if a source's maximum hourly potential to emit immediately prior to the proposed modification is less than the source's post-modification maximum hourly potential to emit. The amount of emission increase will be determined by comparing pre-modification and post-modification emissions on an annual basis by using: (1) an operating schedule of 24 hours per day, 365 days per year; or (2) a permit condition limiting mass emissions.

(e) Trading Zones Restrictions

Any increase in an annual Allocation to a level greater than the facility's starting plus non-tradable Allocations, and all emissions from a new or relocated facility must be fully offset by obtaining RTCs originated in one of the two trading zones as illustrated in the RECLAIM Trading Zones Map. A facility in Zone 1 may only obtain RTCs from Zone 1. A facility in Zone 2 may obtain RTCs from either Zone 1 or 2, or both.

(f) Offsets

The Facility Permit for a new or modified facility shall require compliance with this subdivision, if applicable.

(1) Any facility which was required to provide offsets pursuant to paragraphs (b)(2), or subparagraph (c)(4)(B) or any new facility required to provide offsets pursuant to paragraph (c)(2) shall, at the commencement of each compliance year, hold RTCs, including any RTCs from Table 9 in Rule 2002, in an amount equal to the amount of such required offsets. The Facility Permit holder may reduce the amount of offsets required pursuant to this subdivision by accepting a permit condition limiting emissions which shall serve in lieu of the starting Allocation plus non-tradable credits for purposes of paragraph (c)(4).

(2) Except for the RTCs referenced in Table 9 of Rule 2002, ~~Unused~~ unused RTCs acquired to comply with this subdivision or with paragraphs (b)(2), (c)(2), or subparagraph (c)(4)(B) may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year.

(3) In lieu of compliance with paragraph (f)(2), the Facility Permit holder may accept a permit condition limiting quarterly emissions from the facility. A facility with quarterly emission limits may sell, at any time after the end of that quarter and prior to the end of the reconciliation period for that compliance year, unused RTCs acquired pursuant to this subdivision, excluding the RTCs referenced in Table 9 of Rule 2002, at the amount not to exceed the difference between the permitted emission limit for that quarter and the emissions during that quarter as reported to the District in the Quarterly Emission Certification. Any facility with quarterly certified emissions exceeding the quarterly emission limit for any quarter may sell RTCs, excluding the RTCs referenced in Table 9 of Rule 2002, only during the reconciliation period for the fourth quarter of the applicable compliance year. If there are a total of three exceedances in any five consecutive compliance years, the facility shall permanently comply with paragraph (f)(2) in lieu of (f)(3).

(g) Additional Federal Requirements for Major Stationary Sources

The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, as defined in the Clean Air Act, 42 U.S.C. Section 7511a(e), unless the applicant:

(1) certifies that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards (42 U.S.C. Section 7503(a)(3)); and

(2) submits an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification (42 U.S.C. Section 7503(a)(5));

(3) Compliance Through California Environmental Quality Act

The requirements of paragraph (g)(2) may be met through compliance with the California Environmental Quality Act in the following manner.

(A) if the proposed project is exempt from California Environmental Quality Act analysis pursuant to a statutory or categorical exemption pursuant to Title 14, California Code of Regulations, Sections 15260 to 15329, paragraph (g)(2) shall not apply to that project;

(B) if the proposed project qualifies for a negative declaration pursuant to Title 14 California Code of Regulations, Section 15070, or a mitigated negative declaration as defined in Public Resources Code Section 21064.5, paragraph (g)(2) shall not apply to that project; or

(C) if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations, Section 15080 et seq., paragraph (g)(2) shall be deemed satisfied.

(4) Protection of Visibility

(A) Conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tons/year of NO_X; and the location of the source, relative to the closest boundary of a specified_Federal Class I area, is within the distance specified in Table 4-1.

Table 4-1

Federal Class I Area	*Distance (km)*
Agua Tibia	28
Cucamonga	28
Joshua Tree	29
San Gabriel	29
San Gorgonio	32
San Jacinto	28

(B) In relation to a permit application subject to the modeling analysis required by subparagraph (g)(4)(A), the Executive Officer shall:

(i) deem a permit application complete only when the applicant has complied with the requisite modeling analysis for plume visibility pursuant to subparagraph (g)(4)(A);

(ii) notify and provide a copy of the complete permit application file to the applicable Federal Land Manager(s) within 30 calendar days after the application has been deemed complete and at least 60 days prior to final action on the permit application;

(iii) consider written comments, relative to visibility impacts from the new or modified source, from the responsible Federal Land Manager(s), including any regional haze modeling performed by the Federal Land Manager(s), received within 30 days of the date of notification when determining the terms and conditions of the permit;

(iv) consider the Federal Land Manager(s) findings with respect to the geographic extent, intensity, duration, frequency and time of any identified visibility impairment of an affected Federal Class I area, including how these factors correlate with times of visitor use of the Federal Class I area, and the frequency and timing of natural conditions that reduce visibility; and,

(v) explain its decision or give notice as to where to obtain this explanation if the Executive Officer finds that the Federal Land Manager(s) analysis does not demonstrate that a new or modified source may have an adverse impact on visibility in an affected Federal Class I area.

(C) If a project has an adverse impact on visibility in an affected Federal Class I area, the Executive Officer may consider the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, the useful life of the source, and all other relevant factors in determining whether to issue or deny the Permit to Construct or Permit to Operate.

(h) Public Notice

The applicant shall provide public notice, if required, pursuant to Rule 212 - Standards for Approving Permits.

(i) Rule 1401

All new or modified sources shall comply with the requirements of Rule 1401 - New Source Review of Carcinogenic Air Contaminants, if applicable.

(j) Compliance with State and Federal New Source Review Requirements

The Executive Officer will report to the District Governing Board regarding the effectiveness of Rule 2005 in meeting the state and federal New Source Review requirements for the preceding year. The Executive Officer may impose permit conditions to monitor and ensure compliance with such requirements. This report shall be incorporated in the Annual Program Audit Report prepared pursuant to Rule 2015(b)(1).

(k) Exemptions

(1) Functionally identical source replacements are exempt from the requirements of subparagraph (c)(1)(B) of this rule.

(2) Physical modifications that consist of the installation of equipment where the modification will not increase the emissions rate of any RECLAIM pollutant, and will not cause an increase in emissions above the facility's current year Allocation, shall be exempt from the requirements of paragraph (c)(2).

(3) Increases in hours of operation or throughput for equipment or processes permitted prior to October 15, 1993 that the applicant demonstrates would not violate any permit conditions in effect on October 15, 1993 which were imposed in order to limit emissions to implement New Source Review offset requirements, shall be exempt from the requirements of this rule.

(4) Increase to RECLAIM emission concentration limits or emission rates not associated with Best Available Control Technology permit conditions provided that the increase is not a result of any modification to equipment shall be exempt from the requirements of this rule.

(5) The requirements under subparagraphs (b)(1)(B) and (c)(1)(B), and clause (c)(4)(A)(ii) shall not apply to equipment used exclusively on a standby basis for non-utility electrical power generation or any other equipment used on a standby basis in case of emergency, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter or equivalent method and is listed as emergency equipment in the Facility Permit.

APPENDIX A

The following sets forth the procedure for complying with the air quality modeling requirements. An applicant must either (1) provide an analysis approved by the Executive Officer or designee, or (2) show by using the Screening Analysis below, that a significant change (increase) in air quality concentration will not occur at any receptor location for which the state or national ambient air quality standard for NO_2 is exceeded.

Table A-1 of the screening analysis is subject to change by the Executive Officer, based on improved modeling data.

SCREENING ANALYSIS

Compare the emissions from the equipment you are applying for to those in Table A-1. If the emissions are less than the allowable emissions, no further analysis is required. If the emissions are greater than the allowable emissions, a more detailed air quality modeling analysis is required.

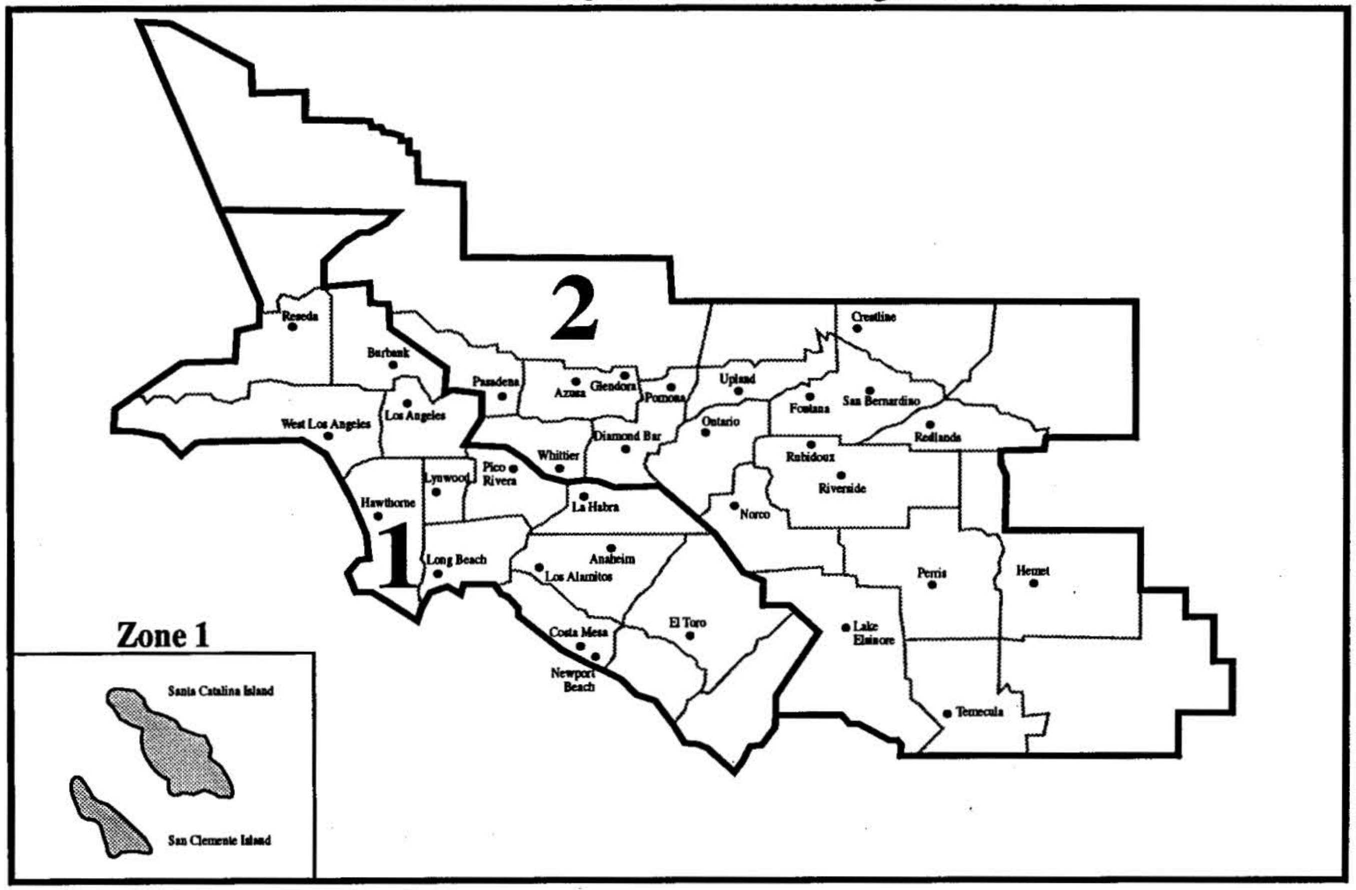
Table A-1
Allowable Emissions
for Noncombustion Sources and for
Combustion Sources less than 40 Million BTUs per hour

Heat Input Capacity (million BTUs/hr)	NOx (lbs/hr)
Noncombustion Source	0.068
2	0.20
5	0.31
10	0.47
20	0.86
30	1.26
40	1.31

Table A-2
Most Stringent Ambient Air Quality Standard and
Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 ug/m^3	1 pphm	20 ug/m^3
	Annual	5.3 pphm	100 ug/m^3	0.05 pphm	1 ug/m^3

RECLAIM Trading Zones
South Coast AQMD Air Monitoring Stations



APPENDIX B

MODELING ANALYSIS FOR VISIBILITY

(a) The modeling analysis performed by the applicant shall consider:

(1) the net emission increase from the new or modified source; and

(2) the location of the source and its distance to the closest boundary of specified Federal Class I area(s).

(b) Level 1 and 2 screening analysis for adverse plume impact pursuant to paragraph (g)(4) of this rule for modeling analysis of plume visibility shall consider the following applicable screening background visual ranges:

Federal Class I Area	Screening Background Visual Range (km)
Agua Tibia	171
Cucamonga	171
Joshua Tree	180
San Gabriel	175
San Gorgonio	192
San Jacinto	171

For level 1 and 2 screening analysis, no adverse plume impact on visibility results when the total color contrast value (Delta-E) is 2.0 or less and the plume contrast value (C) is 0.05 or less. If these values are exceeded, the Executive Officer shall require additional modeling. For level 3 analysis the appropriate background visual range, in consultation with the Executive Officer, shall be used. The Executive Officer may determine that there is no adverse visibility impact based on substantial evidence provided by the project applicant.

(c) When more detailed modeling is required to determine the project's visibility impact or when an air quality model specified in the Guidelines below is deemed inappropriate by the Executive Officer for a specific source-receptor application, the model may be modified or another model substituted with prior written approval by the Executive Officer, in consultation with the federal Environmental Protection Agency and the Federal Land Managers.

(d) The modeling analysis for plume visibility required pursuant to paragraph (g)(4) of this rule shall comply with the most recent version of:

(1) "Guideline on Air Quality Model (Revised)" (1986), supplement A (1987), supplement B (1993) and supplement C (1994), EPA-450/2-78-027R, US EPA, Office of Air Quality Planning and Standards Research Triangle Park, NC 27711; and

(2) "Workbook for Plume Visual Impact Screening and Analysis (Revised)," EPA-454-/R-92-023, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711;

(3) "User's Manual for the Plume Visibility Model (PLUVUE II) (Revised)," EPA-454/B-92-008, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 (for Level-3 Visibility Analysis)

PROPOSED AMENDED RULE 2011 PROTOCOL- CHAPTER 3

PROCESS UNITS - PERIODIC REPORTING AND RULE 219 EQUIPMENT

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CHAPTER 3 - PROCESS UNITS - PERIODIC REPORTING

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Process units may share fuel meters if each equipment has the same emission factor. This chapter also includes the equations describing the methods used to calculate SO_x process unit emissions and the reporting procedures. The interim reporting period does not apply to process units since existing fuel metering equipment or timers shall be used- starting January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

A. GENERAL REQUIREMENTS

1. The equipment-specific or category-specific starting emission factor found in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) shall be used for quantifying quarterly mass emissions for a SOx process unit.

2. Instead of using the equipment-specific or category-specific starting emission factor found in Table 2 of Rule 2002, the Facility Permit holder of a process unit may apply to the Executive Officer to use a representative emission factor or alternative emission factor for purposes of calculating SO_x emissions. The alternative emission factor shall be established by the requirements provided in Chapter 6, Subdivision E.

3. The Facility Permit holder of a process unit shall use an emission factor or alternative emission factor to calculate the mass emission according to the methodology specified in Chapter 3, Subdivision B, Paragraph 2. (fuel totalizing meters) or Chapter 3, Subdivision B, Paragraph 3, Subparagraph a (timers).

4. The Facility Permit holder of each SO_x process unit shall use a totalizing fuel meter or timer as applicable and specified in the Facility Permit for each affected equipment to measure and report the variables listed in Tables 3-A and 3-B, respectively, for each equipment.

5. The Facility Permit holder of each SO_x process unit shall monitor, report and maintain the following records on a quarterly basis:

    a. Type and quantity of fuel burned in units of million standard cubic feet per quarter (mmscf per quarter) for gaseous fuels or thousand gallons per quarter (mgal per quarter) for liquid fuels, expressed with three significant figures minimum; or

    b. Total hours of operation.

6. The Facility Permit holder of each SO_x process unit shall also provide any other data necessary for calculating the emission rates of oxides of sulfur as determined by the Executive Officer.

7. Fuel meters and/or timers must be non-resettable and tamper-proof. They shall have seals installed by the meter/timer manufacturer to prove the integrity of the measuring device.

    Meters which are unsealed for maintenance or repairs shall be resealed by an authorized manufacturers representative.

B. EMISSION CALCULATIONS FOR REPORTED DATA

1. Quarterly Mass Emissions for Interim Periods (January 1, 1994 thru December 31, 1994 for Cycle 1 facilities; and July 1, 1994 thru June 30, 1995 for Cycle 2 facilities)

a. Pursuant to Rules 2011(d)(3) and 2011(f)(2), starting January 1, 1994 for Cycle 1 facilities, and starting July 1, 1994 for Cycle 2 facilities, the quarterly emission of each process unit shall be calculated and recorded according to:

$$E_{ip} = \sum_{j=1}^{r} d_j \times EF_{sj} \qquad \text{(Eq.15)}$$

where:

E_{ip} = The quarterly mass emission of sulfur oxides for interim period (lb/quarter).

d_j = The quarterly fuel usage for each type of fuel recorded as mmscf/quarter or mgal/quarter.

EF_{sj} = The starting emission factor used to calculate unit emissions in the initial allocation, as specified in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x) (lb/mmscf or lb/mgal,).

r = The number of different types of fuel.

Example calculation: IC engine burning natural gas

Starting Emission factor = 0.60 lb/mmscf
Quarterly fuel usage = 2 mmscf/quarter

E_{ip} = (0.60) x (2.0)
= 1.2 lb/quarter

2. Totalizing Fuel Meter Based Calculations

The Facility Permit holder of each equipment in a SO_x process unit when equipped with a totalizing fuel meter shall use emission factor listed in Table 2 of Rule 2002 or alternative emission factors established according to the methodology provided in Chapter 4 to obtain the quarterly mass emissions according to:

$$E_{EF} = \sum_{k=1}^{n} d_k \times EF_k \qquad \text{Eq.15)}$$

where:

E_{EF} = The quarterly emissions of SO_x obtained using emission factor (lb/quarter.)

d_k = The quarterly fuel usage for each type of fuel (mmscf/quarter or mgal/quarter.)

EF_k = The emission factor as specified in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x) (lb/mmscf, lb/mgal or lb/mbbl) or an alternative emission factor proposed by the Facility Permit holder as established from the source test requirement provided in Chapter 4

k = Each type of gaseous or liquid fuel consumed by each process unit throughout the quarter.

n = The total number of different types of fuel consumed by each process unit throughout the quarter

3. Timer-Based Emission Calculations

If the SOx process unit is equipped with a timer~~.~~, the Facility Permit holder shall quantify~~*estimate*~~ the quarterly fuel usage for each affected equipment according to Eq. 17 - Eq. 20 and calculate~~*estimate*~~ the quarterly mass emissions according to Eq. 16 - Eq. 20.

a. Quarterly Fuel Usage for Each Affected SO_x Process Unit

If the SO_x process unit does not measure ~~a~~ fuel usage with a fuel meter, the quarterly fuel usage for each affected equipment in a process unit shall be ~~*estimated*~~ quantified according to:

$$d = d_{pu} \times (H/H_{pu}) \qquad \text{(Eq.17)}$$

Where:

d = ——The ~~estimated~~ quarterly fuel usage of an affected SO_x process unit without a dedicated fuel meter (mmscf/quarter or mgal/quarter).

d_{pu} = The quarterly fuel usage of all SO_x process units at the facility (mmscf/quarter or mgal/quarter).

H = The quarterly heat input of an affected SO_x process unit without a dedicated fuel meter (mmBtu/quarter).

H_{pu} = ——The quarterly heat input of all SO_x process units at the facility (mmBtu/quarter).

Example Calculation:

d_{pu} = 1,587 mmscf/quarter

H = 5,400 mmBtu/quarter

H_{pu} = 27,000 mmBtu/quarter

d = d_{pu} x (H/H_{pu})

d = 1,587 mmscf/quarter x (5,400 mmBtu/quarter – 27,000 mmBtu/quarter

d = 317.4 mmscf/quarter

The quarterly fuel usage for all SO_x process units at the facility (d_{pu}) shall be calculated according to the following equation:

$$d_{pu} = d_{fac} - d_{major} \quad \text{(Eq.18)}$$

where:

d_{fac} = The quarterly fuel usage of all major sources and SO_x process units at the facility (mmscf/quarter or mgal/quarter).

d_{major} = The quarterly fuel usage of all major SO_x sources at the facility (mmscf/quarter or mgal/quarter).

Example Calculation:

d_{fac} = 58 mmscf/quarter
d_{major} = 42 mmscf/quarter
d_{pu} = F_{fac} - F_{major}
d_{pu} = 58 - 42
d_{pu} = 16 mmscf/quarter

The quarterly heat input of all SO_x process units at the facility (H_{pu}) shall be calculated according to:

$$H_{pu} = \sum_{i=1}^{n}(R_i \times T_i) \qquad \text{(Eq.19)}$$

where:

R_i = The maximum rated heat input capacity of a SO_x process unit (mmBtu/hr).

T_i = The quarterly accumulated operation hours for a SO_x process unit (hr/quarter).

i = Each process unit

n = The total number of SO_x process units at the facility.

Example Calculation:

R_1 = 3.5 mmBtu/hr
R_2 = 2.7 mmBtu/hr
T_1 = 480 hr/quarter
T_2 = 120 hr/quarter

$$H_{pu} = \sum_{i=1}^{2} (R_i \times T_i)$$

H_{pu} = (3.5 x 480) + (2.7 x 120)
H_{pu} = 2004 mmBtu/quarter

The maximum rated heat input capacity of all SO_x process units shall be in units of mmBtu/hr. Since internal combustion engines are usually rated in units of brake horse power, the maximum rated heat input capacity of an engine shall be computed as follows.

$$R = 0.002545 \times bhp / eff \qquad \text{(Eq.20)}$$

where:

R	=	The maximum rated heat input capacity
eff	=	The manufacturer's rated efficiency @LHV x (LHV/HHV)
	=	0.25, if not provided by the operator
bhp	=	The manufacturer's rated shaft output in brake horse power

Example Calculation:

eff	=	0.25
bhp	=	75 bhp
R	=	0.002545 x bhp / eff
R	=	0.002545 x 75/.25
R	=	0.7635 mmBtu/hr

If gas turbines are rated in kilowatts, the rating shall be converted to mmBtu/hr by applying the manufacturer's heat rate (in mmBtu/kw-hr). If the manufacturer's heat rate is not available, a default value of 15,000 Btu/kw-hr shall be used.

Example Calculation:

Quarterly fuel usage for an ICE with maximum rated bhp of 90 bhp, 0.25 eff and a boiler rated at 4 mmBtu/hr being served by one fuel totalizer reading 10.5 mmscf. The boiler and ICE burn landfill gas.

I.C.E.= 90 bhp Boiler= 4 mmBtu/hr C_g = 80 ppmv for landfill gas
Fuel meter reading = F_{pu} = 10.5 mmscf

I.C.E.

R = 0.002545 x 90/.25 = 0.916 mmBtu/hr
t = 3 hr/day x 7 days/wk. x 4 wk./mo. x 3 mo/qtr = 252 hr/qtr
H_{ice} = R x t = 0.916 x 252 = 230.8 mmBtu/qtr

Boiler

H_{boiler} = 4 mmBtu/hr x 24 hr./day x 7 day/wk. x 4 wk./mo. x 3 mo/qtr
H_{boiler} = 8064 mmBtu/qtr.
H_{pu} = 230.8 + 8064 = 8294.8 mmBtu/qtr.

$d_{ice} = d_{pu} \times (H_{ice}/H_{pu})$
= 10.5 mmscf/qtr. x (230.8/8294.8)
= .292 mmscf/qtr.

$d_{boiler} = d_{pu} \times (H_{boiler}/H_{pu})$
= 10.5 mmscf/qtr. x (8064/8294.8)
= 10.2 mmscf/qtr.

$E_{ice} = d_{ice} \times C_g \times 0.166$
E_{ice} = .292 mmscf/qtr x 80 ppmv x 0.166
E_{ice} = 3.88 lb/qtr.

$E_{boiler} = d_{boiler} \times C_g \times 0.166$
E_{boiler} = 10.2 mmscf/qtr x 80 ppmv x 0.166
E_{boiler} = 135 lb/qtr.

$E = E_{ice} + E_{boiler}$ = 3.88 + 135 = 138.88 lb/qtr.

C. TOTAL QUARTERLY EMISSIONS CALCULATION FOR ALL SO_X PROCESS UNITS AT THE FACILITY

Quarterly SO_x emissions of all SO_x process units at the facility shall be quantified~~estimated~~ according to:

$$E = \sum_{i=1}^{m} E_{EF} \qquad \text{(Eq.21)}$$

where:

E = The quarterly total emissions of SO_x for all SO_x process units (lb/quarter).

E_{EF} = The quarterly emissions of SO_X obtained using emission factor (lb/quarter).

i = Each process unit

m = The number of process units at the facility.

D. REPORTING PROCEDURES

1. The Facility Permit holder of any SO_x process unit that opts to monitor at the major source monitoring level shall meet the requirements set forth in Chapter 2 - "Major Sources - Continuous Emission Monitoring System."

2. The total recorded quarterly fuel usage data and SO_x emissions in pounds per quarter for all SO_x process units in any facility without RTU shall be recorded in a format approved by the Executive Officer and shall be submitted to the District as part of the Quarterly Certification of Emissions required by Rule 2004.

3. The Facility Permit holder of each SO_x process unit shall maintain daily records of hours of operation or quarterly usage for each SO_x process unit.

4. Any changes made in type of fuel used shall be recorded by the Facility Permit holder.

E. FUEL METER SHARING

1. A single totaling fuel meter shall be allowed to measure and record the fuel usage of more than one equipment in a process unit, provided that each piece of equipment elects for the same emission factor or alternative emission factor as specified in the Facility Permit.

2. Fuel meter sharing for the interim period shall be for those equipment in a process unit with the same emission factor.

F. RULE 219 EQUIPMENT

1. Emission Determination and Reporting Requirements

a. The Facility Permit holder shall determine the emissions for one or more equipment exempt under Rule 219 and report the emissions on a quarterly basis as part of the Quarterly Certified Emissions report required by Rule 2004. The Facility Permit holder shall be allowed to use the existing fuel totalizer, the monthly fuel billing statement, or any other equivalent methodology to quantify~~estimate~~ their fuel usage for a quarterly period.

b. Quarterly reporting period shall start on January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

c. The Facility Permit holder of each equipment shall maintain the quarterly fuel usage data for all equipment exempt under Rule 219 for three years. Such data shall be made available to District staff upon request.

d. The fuel usage for equipment exempt under Rule 219 may be used in conjunction with process units provided that they have the same emission factor.

2. Emission Calculations

The Facility Permit holder shall determine SO_x emissions for equipment exempt under Rule 219 as follows:

$$E_{EF} = \sum_{k=1}^{n} d_k \times EF_k \qquad \text{(Eq.22)}$$

where:

E_{EF} = The quarterly emissions of SO_x obtained using emission factor (lb /quarter).

d_k = The quarterly fuel usage for each type of fuel (mmscf/quarter or mgal/quarter).

EF_k = The emission factor as specified in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) (lb/mmscf, or lb/mgal or lb/mbbl or an alternative emission factor proposed by the Facility Permit holder as established from the source test requirement provided in chapter 4.

k = Each type of gaseous or liquid fuel consumed by each process unit throughout the quarter.

n = The total number of different types of fuel consumed by each process unit throughout the quarter.

3. Missing Data Periods

The Facility Permit holder shall determine SOx emissions for equipment exempt under Rule 219 using the substitute data procedures specified in Subdivision G of this Chapter for any quarter for which the Facility Permit holder did not obtain and record valid fuel consumption data as required by Subdivision F Paragraphs 1 and 2 of this Chapter.

G. SUBSTITUTE DATA PROCEDURES

1. For each process unit or process units using a common fuel meter, elapsed time meter, or equivalent monitoring device, the Facility Permit holder shall provide substitute data as described below whenever a valid quarter of usage data has not been obtained and recorded. Alternative data, based on a back-up fuel meter, elapsed time meter, or equivalent monitoring device, is acceptable for substitution if the Facility Permit holder can demonstrate to the Executive Officer that the alternative system is fully operational during meter down time and within + or - 2% accuracy. The substitute data procedures are retroactively applicable from the adoption date of the RECLAIM program.

2. Whenever data from the process monitor is not available or not recorded for the affected equipment or when the equipment is not operated within the parameter range specified in the Facility Permit, the Facility Permit holder shall calculate substitute data for each quarter, when valid data has not been obtained, according to the following procedures.

   a. For a missing data period less than or equal to one quarter, substitute data shall be calculated using the process unit(s) average quarterly fuel usage for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   b. For a missing data period greater than one quarter, substitute data shall be calculated using the process unit(s) highest quarterly fuel usage data for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   c. If the facility has no records, substitute data shall be calculated using 100% uptime during the substitution period and the process unit(s) maximum rated capacity and uncontrolled emission factor for each quarter of missing data.

TABLE 3-A

MEASURED VARIABLES FOR ALL SO_x PROCESS UNITS

EQUIPMENT	MEASURED VARIABLES
Any SO_x unit that is not categorized as a major source	1. Fuel usage; or Operating time; 2. Production rate; 3. Fuel sulfur content.

TABLE 3-B

REPORTED VARIABLES FOR ALL SO_x PROCESS UNITS

EQUIPMENT	REPORTED VARIABLES
Any SO_x unit that is not categorized as a major source	Quarterly SO_x emissions from each unit.

PROPOSED AMENDED RULE 2011 PROTOCOL - ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. QUALITY CONTROL PROGRAM

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

Explain how each component of the CEMS shall be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that shall be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However, facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the SOx protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be given is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments during each day in which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, during each day that emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Test, record, and compute the calibration error of each SO_2 pollutant concentration monitor, fuel gas sulfur content monitor, if applicable, and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in– Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration or the fuel gas sulfur content has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration or the fuel gas sulfur content has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

i. Design Requirements for Calibration Error Testing of SO_x Concentration Monitors, the Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Design and equip each SO_x concentration monitor, fuel gas sulfur content monitor, and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor, fuel gas sulfur content and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for SO_x Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Measure the calibration error of each SO_2 concentration analyzer, fuel gas sulfur analyzer, and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking on all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the SO_x concentration monitors, the fuel gas sulfur content monitors, and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = Percentage calibration error based on the span range

R = Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation :

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Chapter 2, Subdivision B, Paragraph 1, Subparagraph c of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the SOx monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an SO_2 concentration monitor or a fuel gas sulfur content monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, dscfh, and percent volume. Program monitors that automatically adjust data -to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the SO_X pollutant concentration monitor, flow monitoring system, and SOx emission rate measurement system are~~is~~ 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are either disconnected or opened and either flanges or equivalent sealing devices are placed at both ends of the disconnected or opened lines, and

ii. The fuel meter(s) for the disconnected fuel or opened feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

This paragraph applies separately for each unrelated, independent event. For any hour that fuel flow records are not available to verify no fuel flow, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that either only operates under a California Independent System Operator (Cal ISO) contract or is owned and operated by a municipality may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows:

i. The semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment was due;

ii. The assessment was not completed due to lack of adequate operational time; and

iii. A CGA was conducted and passed within the calendar quarter when the assessment was due.

e~~a~~. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each $S0_2$ pollutant concentration monitor, fuel gas sulfur content monitor, stack gas volumetric flow rate measurement systems, and the $S0_2$ mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, ~~and~~ 12, and 13 and Attachment B of the Protocol for ~~Proposed~~ Rule 2011. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, ~~and~~ 12, and 13 and Attachment B (bias test) of the ~~Draft~~ Protocol for ~~Proposed~~ Rule 2011.

f~~b~~. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor, a fuel gas sulfur content monitor, or the $S0_2$ emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

g~~c~~. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

h~~d~~. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.e~~a~~.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.h~~d~~.iii.

If any of the requirements under Subclauses B.2.h~~d~~.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours ; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

PROCESS UNITS - PERIODIC REPORTING AND RULE 219 EQUIPMENT

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CHAPTER 4 - PROCESS UNITS PERIODIC REPORTING AND RULE 219 EQUIPMENT

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Process units are one or more pieces of equipment which are listed in Table 1-C. The process units emissions are reported quarterly as shown in Table 4-A and based primarily on fuel consumption or operating time in conjunction with an emission factor. The requirements and procedures for an emission factor and election conditions for an alternative emission factor or concentration limit shall apply to process units. For equipment designated as exempt from permit in Rule 219 emissions shall be determined according to the methodology specified in this Chapter 4, subdivision F.

Process units and equipment exempt from permit as designated in Rule 219 may share fuel meters if each equipment has the same emission factor. This chapter also includes the equations describing the methods used to calculate NO_X process unit emissions and the reporting procedures. The interim reporting period does not apply to process units since existing fuel metering equipment or timers- shall be used starting January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

A. MONITORING, REPORTING, AND RECORDKEEPING REQUIREMENTS

1. The category-specific starting emission factor found in Table 1 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Sulfur (SO_x) shall be used for quantifying quarterly mass emissions for a NO_x process unit.

2. The Facility Permit holder of a process unit may request a category-specific emission rate that is reliable, accurate, and representative for purposes of calculating NO_x emissions. The emission rate shall be determined based on the source testing protocol specified in Chapter 5. The Facility Permit holder of a process unit may apply for a concentration limit for purposes of calculating NO_x emissions.

3. The Facility Permit holder of a process unit– shall calculate the mass emissions according to the methodology specified in Paragraph 4.B.2. (totalizing fuel meters) or 4.B.3.a. (timers).

4. The Facility Permit holder of each NO_x Process Unit shall use a totalizing fuel meter or timer as applicable, as specified in the Facility Permit for each NO_X process unit to measure and report the variables listed in Tables 4-A and 4-B, respectively, for each NO_X process unit.

5. Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors shall be tested, when required, as installed for relative accuracy using reference methods to determine stack flow.

   a. The relative accuracy of the fuel flow meter must be determined using District reference Methods 1-4 and a three-run relative accuracy audit (RAA) at normal operating load. The accuracy of the fuel flow measuring system must be determined using the following equation:

$$A = (C_m - C_a)/C_a \times 100\% \qquad \text{(Eq. 15a)}$$

where:

A = accuracy of the fuel flow meter (%)

C_m = average flow rate response (scfh)

C_a = average reference method flow rate (scfh)

The value of fuel flow meter accuracy, as defined in Eq. 15a, shall be less than or equal to 15%.

b. Other acceptable alternatives to the above procedures used to determine the relative accuracy of the facility fuel flow meter or stack flow meter are listed under Chapter 3, Subdivision H.

6. Fuel meters and/or timers have to be non-resettable and tamper-proof. They have to have seals installed by the meter/timer manufacturer to prove the integrity of the measuring device.

Meters which are unsealed for maintenance or repairs shall be resealed by an authorized manufacturers representative.

7. The Facility Permit holder of each NO_x process unit shall monitor, report, and maintain the following records on a quarterly basis:

a. Type and quantity of fuel burned, in units of millions of standard cubic feet per quarter (mmscf per quarter) for gaseous fuels or thousand gallons per quarter (mgal per quarter) for liquid fuels, expressed to at least three significant figures; or

b. Total hours of operation; and

c. Production/Processing/Feed rate.

8. The Facility Permit holder of each NO_x process unit shall also provide any other data necessary for calculating the emission rates of nitrogen oxides as determined by the Executive Officer.

B. EMISSION CALCULATION FOR REPORTING DATA

1. Quarterly Mass Emissions for Interim Periods

Pursuant to Rule 2012 (f) (1), between January 1, 1994 and December 31, 1994 for Cycle 1 facilities, and between July 1, 1994 and June 30, 1995 for Cycle 2 facilities, the monthly emission of each process unit shall be calculated and recorded according to:

$$E_{ip} = \sum_{j=1}^{r} d_j \quad x \quad EF_{sj} \qquad \text{(Eq.22)}$$

where:

E_{ip} = The quarterly mass emission of nitrogen oxides for interim period (lb/quarter).

d_j = The quarterly fuel usage for each type of fuel recorded as mmscf/quarter or mgal/quarter).

EF_{sj} = The starting emission factor used to calculate unit emissions in the initial allocation, as specified in Table 1 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Sulfur (SO_X) (lb/mmscf, lb/mgal).

r = The number of different types of fuel consumed per quarter.

j = Each type of fuel.0

Example calculation: Boiler burning natural gas, rated 6 mmBtu/hr, in compliance with Rule 1146
starting year 1994
Emission factor = 49.18 lb/mmscf
Quarterly fuel usage = 1.1 mmscf per quarter

E_{ip} = (49.18) x (1.1)
= 54.1 lb/quarter

Applicable emission factor is also found in Volume II - Supporting Documentation, Appendix II-F - Methodology for NO_x and SO_x Starting and Ending Allocation Factors, Table 2-4 - Startpoint 1994 Emission Factors for Nitrogen Oxides.

2. Totalizing Fuel Meter-Based Emission Calculation

The Facility permit holder shall use an emission factor shown in Table 1 of Rule 2002 or in Table 3-D or an approved equipment-specific or category-specific emission rate for each affected NO_x Process Unit to calculate the quarterly emissions according to:

$$E_k = \sum_{j=1}^{r} d_j \times EF_j \qquad \text{(Eq.23)}$$

or

$$E_k = \sum_{j=1}^{r} d_j \times V_j \times ER_j \qquad \text{(Eq.24)}$$

where:

E_k = The quarterly emissions of nitrogen oxides (lb/quarter).

d_j = The quarterly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf/quarter or mgal/quarter)

EF_j = The emission factor specified in Table 1 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Sulfur (SO_X) or specified in Table 3-D (lb/mmscf, lb/mgal). The emission factor found in Table 1 of Rule 2002 may or may not include the appropriate control efficiency.

V_j = The higher heating value of each type of fuel (mmBtu/mmscf or mmBtu/mgal) determined by the Facility Permit holder or assigned from Table 3-D.

ER_j = The equipment-specific or category-specific emission rate; fuel-specific emission rate requested by the Facility Permit holder (lb/mmBtu).

r = The number of different types of fuel consumed per month.

3. Timer-Based Emission Calculations

a. If the NO_x process unit is equipped with a timer, the quarterly fuel usage shall be quantified ~~estimated~~ according to Eq. 25, 26 27, and 28 and the quarterly emissions for each affected NO_x process unit shall be calculated according to Eq. 23 and 24.

If the NO_x process unit does not measure fuel with a totalizing fuel meter, the quarterly fuel consumption for each affected equipment shall be quantified ~~estimated~~ according to:

$$d = d_{pu} \times (H/H_{pu}) \quad \text{(Eq.25)}$$

where:

d = The ~~estimated~~ quarterly fuel consumption of an affected NO_x process unit without a dedicated fuel meter (mmscf/quarter or mgal/quarter).

d_{pu} = The quarterly fuel consumption of all NO_x process units at the facility (mmscf/quarter or mgal/quarter).

H = The quarterly heat input of an affected equipment without a dedicated fuel meter (mmBtu/quarter).

H_{pu} = The quarterly heat input of all NO_x process units at the facility (mmBtu/quarter).

Example Calculation:		
d_{pu}	=	1,587 mmscf/quarter
H	=	5,400 mmBtu/quarter
H_{pu}	=	27,000 mmBtu/quarter
d	=	d_{pu} x (H/H_{pu})
d	=	1,587 mmscf/qtr x (5,400 mmBtu/qtr ÷27,000 mmBtu/qtr)
d	=	317.4 mmscf/qtr

The quarterly fuel usage for all the NO_x process units at the facility (d_{pu}) shall be calculated according to:

$$d_{pu} = d_{fac} - (d_{large} + d_{major}) \quad \text{(Eq.26)}$$

where:

d_{fac} = The quarterly fuel usage of all major and large sources and NO_x process units at the facility (mmscf/quarter or mgal/quarter).

d_{major} = The quarterly fuel usage of all major NO_x sources at the facility (mmscf/quarter or mgal/quarter).

d_{large} = The quarterly fuel usage of all large NO_x sources at the facility (mmscf/quarter or mgal/quarter).

Example Calculation:		
d_{fac}	=	174 mmscf/quarter
d_{major}	=	126 mmscf/quarter
d_{large}	=	30 mmscf/quarter
d_{pu}	=	d_{fac} - (d_{large} + d_{major})
d_{pu}	=	174 - (126 + 30)
d_{pu}	=	18 mmscf/quarter

The quarterly heat input of all the NO_x process units at the facility (H_{pu}) shall be calculated according to:

$$H_{pu} = \sum_{i=1}^{n} (R_i \times T_i) \quad \text{(Eq.27)}$$

where:

R_i = The maximum rated fuel capacity of a NO_x process unit (mmBtu/hr).

T_i = The quarterly accumulated operation hours for a NO_x process unit (hrs/quarter).

n = The total number of NO_x process units at the facility.

Example Calculation:		
R_1	=	3.5 mmBtu/hr
R_2	=	2.7 mmBtu/hr
T_1	=	480 hr/quarter
T_2	=	120 hr/quarter
H_{pu}	=	$\sum_{i=1}^{2} (R_i \times T_i)$
H_{pu}	=	(3.5 x 480) + (2.7 x 120)
H_{pu}	=	2004 mmBtu/quarter

The maximum rated heat input capacity of all NO_x process units shall be in units of mmBtu/hr. Since internal combustion engines are usually rated in units of brake horse power, the maximum rated heat input capacity of an engine shall be computed as follows:

$$R = 0.002545 \times bhp / eff \qquad \text{(Eq.28)}$$

where:

R = The maximum rated heat input capacity

eff = The manufacturer's rated efficiency @LHV x (LHV/HHV)

= 0.25, if not provided by the operator

bhp = The manufacturer's rated shaft output in brake horse power

Example Calculation:		
eff	=	0.25
bhp	=	75 bhp
R	=	0.002545 x bhp / eff
R	=	0.002545 x 75/.25
R	=	0.7635 mmBtu/hr

If gas turbines are rated in kilowatts, the rating shall be converted to mmBtu/hr by applying the manufacturer's heat rate (in mmBtu/kw-hr). If the manufacturer's heat rate is not available, a default value of 15,000 Btu/kw-hr shall be used.

Example Calculation:

Quarterly natural gas fuel usage for an ICE with maximum rated bhp of 90 bhp, 0.25 eff and a boiler rated at 4 mmBtu/hr is being served by one fuel meter reading 10.5 mmscf. The compliance emission rate of both ICE and boiler is 0.3 lb/mmBtu.

ICE = 90 bhp Boiler= 4 mmBtu/hr
Fuel meter reading = d_{pu} = 10.5 mmscf

I.C.E.
R = 0.002545 x 90/.25 = 0.916 mmBtu/hr
t = 3 hr/day x 7 days/wk. x 4 wk./mo. x 3 mo/qtr = 252 hr/qtr
H_{ice} = R x t = 0.916 x 252 = 230.8 mmBtu/ quarter

Boiler
H_{boiler} = 4 mmBtu/hr x 24 hr./day x 7 day/wk. x 4 wk./mo. x 3 mo/qtr
H_{boiler} = 8064 mmBtu/quarter
H_{pu} = 230.8 + 8064 = 8294.8 mmBtu/qtr

$d_{ice} = d_{pu} \times (H_{ice}/H_{pu})$
= 10.5 mmscf/qtr x (230.8/8294.8)
= .298 mmscf/qtr

$d_{boiler} = d_{pu} \times (H_{boiler}/H_{pu})$
= 10.5 mmscf/qtr x (8064/8294.8)
= 10.2 mmscf/qtr

$E_{ice} = d_{ice} \times V \times ER_c$
= 1050 mmBtu/mmscf x 0.30 lb/mmBtu x .298 mmscf/qtr
= 93.87 lb/qtr
$E_{boiler} = d_{boiler} \times V \times ER_c$
= 10.2 mmscf/qtr x 1050 mmBtu/mmscf x 0.3 lb/mmBtu
= 3213 lb/qtr

$E = E_{ice} + E_{boiler}$ = 93.87 + 3213 lb/qtr = 3307 lb/qtr

4. Concentration Limit based Emissions Calculations

When the Facility Permit holder elects to use the concentration limit, the quarterly mass emission shall be calculated and recorded according to one of the following equations:

a. Use the F-factor approach for oxygen except in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or the oxygen content of the stack gas is 19 percent or greater. Process units that are permitted to demonstrate compliance using the procedures in Rule 2012, Appendix A, Chapter 5, Subdivision H shall use the following equation to calculate and record nitrogen oxides mass emission rate even if the oxygen stack gas is 19 percent or greater. The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{O2} \quad [20.9/(20.9 - b)] \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dj} \times d_j \times V_j) \qquad \text{(Eq.28a)}$$

where:

E_k	=	The quarterly mass emission of nitrogen oxides (lb/quarter).
$PPMV_{O2}$	=	The RECLAIM concentration limit as listed in the Facility Permit. (ppmv) and based on standardized oxygen concentration in the exhaust stream.
b	=	The standard concentrations of oxygen as listed in the Facility Permit or as found in Table 3-F. (%).
r	=	The number of different types of fuel.
j	=	Each type of fuel.
$F_{d\,j}$	=	The oxygen-based dry F factor for oxygen for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
d_j	=	The quarterly– fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per quarter or mgal per quarter).
V_j	=	The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal) or determined by a continuous analyzer.

The product ($d_j \times V_j$) shall have units of mmBtu per quarter (mmBtu/quarter).

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

b. If the F-factor approach for oxygen can-not be used, use the F-factor approach for carbon dioxide as specified in 40 CFR Part 60, Appendix A, Method 19, except in cases where the carbon dioxide concentration is less than one volume percent dry, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or non-metered sources of fuel are present (e.g., afterburners). The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{CO2} \times (100/\%CO_2) \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{cj} \times d_i \times V_i) \quad \text{(Eq.28b)}$$

Where:

E_k	=	The quarterly mass emission of nitrogen oxides (lb/quarter).
$PPMV_{CO2}$	=	The RECLAIM concentration limit as listed in the Facility Permit (ppmv) and based on standardized carbon dioxide concentration in the exhaust stream.
$\%CO_2$	=	The standard concentrations of stack gas carbon dioxide as listed in the Facility Permit.
r	=	The number of different types of fuel.
j	=	Each type of fuel.
F_{cj}	=	The carbon dioxide-based dry F factor for carbon dioxide for each type of fuel, the ratio of the dry gas volume of the products of combustion to the

heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.

d_j = The quarterly~~–~~ fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per quarter or mgal per quarter).

V_j = The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal) or determined by a continuous analyzer.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

c. If the F-factor approach for carbon dioxide can~~–~~not be used, the nitrogen oxides mass emission rate shall be determined based on actual monthly stack flow rate from a continuous stack flow monitor and concentration limit at stack conditions as listed in the Facility Permit. The mass emission rate shall be determined by the following equation:

$$E_k = PPMV_{ST} \times 1.195 \times 10^{-7} \times \sum_{j=1}^{N} F_j \qquad \text{(Eq. 28c)}$$

where:

E_k = The quarterly mass emission of nitrogen oxides (lb/quarter).

$PPMV_{ST}$ = The concentration limit at stack condition as listed in the Facility Permit (ppmv).

F_j = Total quarterly stack flow rate (scf/quarter) of stack j.

N = Number of exhaust stacks.

For systems that record hourly exhaust flow rate data, the total quarterly stack flow rate shall be determined by the following equation:

$$F_j = \sum_{i=1}^{M} H_{ij} \qquad \text{(Eq. 28d)}$$

F_j = Total quarterly stack flow rate (scf/quarter) of stack j.

H_{ij} = Hourly stack flow rate (scf/hour) of stack j.

M = Total number of hours for the quarter.

Whenever valid stack flow rate data is not obtained for an hour, the Facility Permit holder shall calculate substitute data using the missing data procedures applicable to flow as set forth in Appendix A, Chapter 3, Subdivision K, Paragraph 2.

C. TOTAL QUARTERLY EMISSIONS CALCULATION FOR ALL NO_X PROCESS UNITS AT THE FACILITY

The quarterly NO_X emissions of all NO_X process units at the facility shall be quantified~~*estimated*~~ according to:

$$E = \sum_{i=1}^{n} E_i \qquad \text{(Eq.29)}$$

$$E_i = \sum_{j=1}^{m} E_j \qquad \text{(Eq. 30)}$$

where:

E = The total quarterly emissions for all NO_X process units

E_i = The quarterly emission of each NO_X process unit (lb/quarter)

E_j = The quarterly emission of each NO_X process unit per type of fuel (lb/quarter)

i = Each type of affected NO_x process unit

j = Each type of fuel

m = The total number of fuels consumed for each affected NO_x process unit per quarter

n = The total number of NO_x process units at the facility.

Example Calculation:

E_1 = 163.8 lb/quarter
E_2 = 78 lb/quarter
E_3 = 120 lb/quarter

$$E = \sum_{i=1}^{n} E_i = 163.8 + 78 + 120$$

$$E = 361.8 \text{ lb/quarter}$$

D. REPORTING PROCEDURES

1. The emissions data in any facility with an RTU shall be reported to Central Station Computer at the end of any quarter and the data shall be computed to determine the quarterly total emissions for each source using Equations 22 through 28 as appropriate.

2. The total fuel usage data for all NO_x process units in any facility without an RTU shall be recorded in a format approved by the Executive Officer and submitted to the District as part of the Quarterly Certified Report required by Rule 2004.

3. The Facility Permit holder of NO_x process units shall maintain daily records of operation hours or quarterly usage rate for each NO_x process unit.

4. Any changes made in type of fuel used and rated capacity for each source shall be recorded by the Facility Permit holder.

5. The Facility Permit holder of any NO_x process unit that opts to monitor at the large source monitoring level shall meet the requirements set forth in "Chapter 3 Large Sources - Continuous Process Monitoring System (CPMS)".

E. FUEL METER SHARING

1. A single totalizing fuel meter shall be allowed to measure the cumulative fuel usage for more than one equipment provided that each equipment elects for the same emission rate or emission factor as specified in the Facility Permit and that any equipment in a process unit does not use the annual heat input in order to be categorized from a large source to a process unit.

2. One or more equipment in a process NO_x unit shall be allowed to share the fuel totalizing meter with the equipment in a process NO_x unit provided that each equipment elects for the same emission rate or emission factor as specified in the Facility Permit.

3. Fuel meter sharing for the interim period shall be allowed for those equipment in a process unit with the same emission rate or emission factor.

F. RULE 219 EQUIPMENT

1. Emission Determination And Reporting Requirements

a. The Facility Permit holder shall determine the emissions for one or more equipment exempt under Rule 219 and report the emissions on a quarterly basis as part of the Quarterly Certified Emissions Report Certification of Emissions required by Rule 2004. The Facility Permit holder shall be allowed to use the existing fuel totalizer, the monthly fuel billing statement, or any other equivalent methodology to quantify~~*estimate*~~ their fuel usage for a quarterly period.

b. Quarterly reporting periods shall start on January 1, 1994 for Cycle 1 Facilities and July 1, 1994 for Cycle 2 facilities.

c. The Facility Permit holder of each equipment shall maintain the quarterly fuel usage data for all equipment exempt under Rule 219 for three years. Such data shall be made available to District staff upon request.

d. The fuel usage for equipment exempt under Rule 219 may be used in conjunction with fuel usage for process units provided that they have the same emission factor.

2. Emission Calculations

The Facility Permit holder shall determine NO_x emissions for equipment exempt under Rule 219 as follows-:

$$E_{219} = \sum_{i=1}^{n} EFR_i \times d_i \qquad \text{(Eq. 31)}$$

where:

E_{219} = The total emissions for equipment exempt under Rule 219 quantified~~estimated~~ over a quarterly period (lb/~~per~~ quarter).

EFR_i = The equipment-specific or category-specific emission factor for each equipment exempt under Rule 219 equipment. The emission factor can be found in Table 3-D (lb/mmscf or lb/mgal). Alternatively, for an equipment certified by US EPA, CARB, or SCAQMD as meeting a certain emission level, an appropriate emission factor equivalent to the certified emission level may be used provided the facility complies with the source test or maintenance requirements specified in paragraph 4.

d_i = The equipment-specific or category-specific fuel usage (mmscf/~~per~~ quarter or mgal/~~per~~ quarter).

n = The number of equipment exempt under Rule 219.

3. Missing Data Periods

The Facility Permit holder shall determine NO_x emissions for equipment exempt under Rule 219 using the substitute data procedures specified in Subdivision G of this Chapter for any quarter for which the Facility Permit holder did not obtain and record valid fuel consumption data as required by Subdivision F, Paragraphs 1 and 2 of this Chapter.

4. Source Testing and Maintenance

Each equipment exempt under Rule 219 with NO_x emissions determined using an alternative emission factor based on a US EPA, CARB, or SCAQMD certified emission level shall either be periodically source tested pursuant to F.4.a. or maintained pursuant to F.4 b.

a. Source Testing

i. Conduct periodic source tests to verify that emissions are less than or equal to the US EPA, CARB, or SCAQMD certified emission level. Each such source test shall comply with the provisions of Chapter 5 D.1. and D.2.

ii. Each device subject to this source testing requirement shall be tested on the same schedule as specified in Table 5-B for Process Unit with Concentration Limit, except in cases where a facility has multiple devices subject to this source testing requirement, all with the same US EPA, CARB, or SCAQMD certification. In such cases the facility operator may conduct the source testing of at least half of the devices with the same certification each five-year period provided each device is source tested at least once every two successive five-year periods.

iii. If a source test determines that an equipment exempt under Rule 219 with NO_x emissions quantification using an emission factor equivalent to the US EPA, CARB, or SCAQMD certified emission level has emissions greater than the emission factor used for emission quantification, emissions from that source and all other sources engaged in meter sharing with that source pursuant to subdivision E of this chapter shall quantify emissions using the appropriate equipment-specific or category-specific emission factor in Table 3-D from the start of the quarter in which the source test was conducted through the end of the quarter in which a subsequent source test demonstrates that the source's emissions are less than or equal to the emission factor.

b. Maintenance

i. Conduct annual maintenance on the equipment to ensure emissions remain at or below the US EPA, CARB, or SCAQMD certified emission level. Promptly after completing such maintenance, verify that the emissions from each device subject to this maintenance requirement remain at or below the US EPA, CARB, or SCAQMD certified emission level with a portable NOx, CO, and oxygen analyzer according to the Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to South Coast Air Quality Management District Rules 1110.2, 1146, and 1146.1.

ii. If an annual maintenance emission check with a portable analyzer determines that an equipment exempt under Rule 219 with NO_x emissions quantification using an emission factor equivalent to the US EPA, CARB, or SCAQMD certified emission level has emissions greater than the emission factor used for emission quantification, emissions from that source and all other sources engaged in meter sharing with that source pursuant to subdivision E of this chapter shall quantify emissions using the appropriate equipment-specific or category-specific emission factor in Table 3-D from the start of the quarter in which the portable analyzer emission check was conducted through the end of the quarter in which a subsequent portable analyzer emission check demonstrates that the source's emissions are less than or equal to the emission factor.

c. Recordkeeping

Each facility that elects to comply with subdivision 2 by implementing the procedures specified in paragraph 4.a. or 4.b. shall keep records of all testing, maintenance, and verification conducted pursuant to those paragraphs for at least three years and make such records available to the Executive Officer upon request.

G. SUBSTITUTE DATA PROCEDURES

1. For each process unit or process units using a common fuel meter, elapsed time meter, or equivalent monitoring device, the Facility Permit holder shall provide substitute data as described below whenever a valid quarter of usage data has not been obtained and recorded. Alternative data, based on a back-up fuel meter, elapsed time meter, or equivalent monitoring device, is acceptable for substitution if the Facility Permit holder can demonstrate to the Executive Officer that the alternative system is fully operational during meter down time and within + or - 2% accuracy. The substitute data procedures are retroactively applicable from the adoption date of the RECLAIM program.

2. Whenever data from the process monitor is not available or not recorded for the affected equipment or when the equipment is not operated within the parameter range specified in the Facility Permit, the Facility Permit holder shall calculate substitute data for each quarter, when valid data has not been obtained, according to the following procedures.

   a. For a missing data period less than or equal to one quarter, substitute data shall be calculated using the process unit(s) average quarterly fuel usage for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   b. For a missing data period greater than one quarter, substitute data shall be calculated using the process unit(s) highest quarterly fuel usage data for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   c. If the facility has no records, substitute data shall be calculated using 100% uptime during the substitution period and the process unit(s) maximum rated capacity and uncontrolled emission factor for each quarter of missing data.

   d. For a process monitor which uses a gas chromatograph or equivalent continuous method to continuously determine the F-factor and higher heating value of the fuel (Rule 2012, Appendix A, Chapter 4, Subdivision B.4.a.i), the Facility Permit holder shall use the stack gas flow rate missing data substitution procedure for major sources (Rule 2011 or 2012, Appendix A, Chapter 2, Subdivision E.2).

TABLE 4-A

MEASURED VARIABLES FOR ALL NO_x PROCESS UNITS

EQUIPMENT	MEASURED VARIABLES
All NO_x process units	1. Fuel usage or exhaust flow rate (for sources with stack flow monitors) or processing/feed rate or operating time 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);

TABLE 4-B

REPORTED VARIABLES FOR ALL -NO_x PROCESS UNITS

EQUIPMENT	REPORTED VARIABLES
All NO_x process units	1. Quarterly mass emissions

PROPOSED AMENDED RULE 2012 PROTOCOL-ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

   Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

   Explain how each component of the CEMS will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

   Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

   Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that will be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the NO_X protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be performed is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments on each day during which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, on each day during which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors and O_2 Monitors

Test, record, and compute the calibration error of each NO_X pollutant concentration monitor and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Paragraph B.1.a.ii. of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales

i. Design Requirements for Calibration Error Testing of NO_x Concentration Monitors and O_2 Monitors

Design and equip each NO_x concentration monitor and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for NO_x Concentration Monitors and O_2 Monitors

Measure the calibration error of each NO_x concentration analyzer and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the NO_x concentration monitors and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R-A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = The percentage calibration error based on the span range

R = The reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = The actual monitoring system response to the calibration gas.

S = The span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the. transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Paragraph B.1.c.i. of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

i. Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the NO_x monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an NO_x concentration monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, DSCFH, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the NO_X pollutant concentration monitor, flow monitoring system, and NOx emission rate measurement system are~~is~~ 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are either disconnected or opened and either flanges or equivalent sealing devices are placed at both ends of the disconnected or opened lines, and

ii. The fuel meter(s) for the disconnected or opened fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

This paragraph applies separately for each unrelated, independent event. For any hour that fuel flow records are not available to verify no fuel flow, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that either only operates under a California Independent System Operator (Cal ISO) contract or is owned and operated by a municipality may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows:

i. The semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment was due;

ii. The assessment was not completed due to lack of adequate operational time; and

iii. A CGA was conducted and passed within the calendar quarter when the assessment was due.

e~~a~~. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each NO_X pollutant concentration monitor, stack gas volumetric flow rate measurement systems, and the NO_X mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, ~~Chapter 2, Subdivision B, Paragraph~~ 11, ~~and Chapter 2, Subdivision B, Paragraph~~ 12, and 18. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs ~~2.B.~~10, ~~2.B.~~11, ~~and 2.B.~~12, and 18.

f~~b~~. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an NO_X pollutant concentration monitor or the NO_X emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the –hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

g~~c~~. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

h~~d~~. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.e~~a~~.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.h~~d~~.iii.

If any of the requirements under Subclauses B.2.h~~d~~.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Final Staff Report

Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM

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List of Acronyms

AC	Annual Operating Cost
AER	Annual Emissions Report
AQMP	Air Quality Management Plan
ASC	Ammonia Slip Catalyst
Basin	South Coast Air Basin
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
CARB	California Air Resources Board
CE	Cost Effectiveness
CEMS	Continuous Emissions Monitoring System
CLN^{TM}	Cheng Low NOx Control Technology
CM	Control Measure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CR	Catalyst Replacement
CY	Compliance Year
DCF	Discounted Cash Flow Method
DLN/DLE	Dry Low NOx/Dry Low Emissions
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
ER	Emission Reductions
ESP	Electrostatic Precipitator
ETS	Environmental Technology Services
^{o} F	Degree Fahrenheit
FCCU	Fluid Catalytic Cracking Unit
GF	Growth Factor
HHV	High Heating Value of Fuel
HRSG	Heat Recovery Steam Generator
H&SC	Health & Safety Codes
~~GF~~IYB	~~Growth Factor~~Infinite Year Block
LCF	Levelized Cash Flow Method
LoTOx^{TM}	Low Temperature Oxidation Process for NOx Control
NAAQS	National Ambient Air Quality Standards
NEC	Norton Engineering Consultants
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
N_2O	Nitrous Oxide
NOx	Nitrogen Oxides
OCS	Outer Continental Shelf
OAQPS	Office of Air Quality Planning and Standards
PAR	Proposed Amended Rule or Proposed Amended Regulation
ppm	Parts Per Million
PWV	Present Worth Values
RACM	Reasonably Achievable Control Measure
RACT	Reasonably Achievable Control Technology
RECLAIM	Regional Clean Air Incentive Market Program

RTC	RECLAIM Trading Credit
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOx	Sulfur Oxides
SRU/TG	Refinery's Sulfur Recovery Unit /Tail Gas Treating Unit
TIC	Total Installed Costs
tpd or TPD	Tons Per Day
Ultra-Cat™	Ultra-Cat Catalyst Filter Manufactured by Tri-Mer Corporation
WHB	Waste Heat Boiler
WGM	Working Group Meeting
WSPA	Western States Petroleum Association

Executive Summary

Background

On October 15, 1993, the South Coast Air Quality Management District (SCAQMD) Governing Board adopted Regulation XX - REgional Clean Air Incentives Market (RECLAIM). Regulation XX includes rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for sources located at RECLAIM facilities. RECLAIM was designed to provide equivalent emission reduction in the aggregate for the facilities in the program compared to what would occur under a command-and-control approach, with flexibility for each facility to find the most cost-effective strategy to meet their emission reduction targets. The program requires robust monitoring to ensure compliance. Over the past more than 20 years, the program has resulted in significant emission reductions. The RECLAIM program started with 392 NOx facilities in 1993. By the end of compliance year 2013, there were 275 facilities in the NOx RECLAIM universe.

Best Available Retrofit Control Technology for RECLAIM

When the NOx RECLAIM program was first adopted, the NOx RECLAIM facilities were issued NOx annual allocations (also known as facility caps), which declined annually from 1993 until 2003 and remained constant after 2003. The annual allocations issued to the NOx RECLAIM facilities reflected the levels of Best Available Retrofit Control Technology (BARCT) envisioned to be in place at the RECLAIM facilities, and were the result of a BARCT analysis conducted in 1993. A BARCT reassessment is required by the California Health & Safety Code (H&SC) §40440 to assess the advancement in control technology and to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that emission reductions from the program contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). The SCAQMD staff conducted a BARCT reassessment for NOx in 2005 and another for SOx in 2010, and subsequently amended the RECLAIM rules to reduce the facility annual allocations. RECLAIM facilities have the flexibility to install air pollution control equipment, change their operations, or purchase RECLAIM Trading Credits (RTCs).

Ozone Non-Attainment Status

On March 12, 2008, the EPA strengthened its ground-level 8-hour ozone standard from 0.08 parts per million (ppm) to 0.075 ppm. On May 21, 2012, the EPA classified two areas in the country, the South Coast and the San Joaquin Valley, as “Extreme” non-attainment areas with respect to the 2008 8-hour ozone standard. The attainment dates for the 1997 and 2008 ozone standards are

June 15, 2024 and July 20, 2032, respectively with emissions reductions and attainment required in the previous calendar year. NOx is a precursor for ozone. Significant reductions in NOx emissions are necessary for the Basin to attain the *federal* 24-hour PM2.5 standard ~~in~~ *by* 2019 and the *federal* ozone ambient air quality standards in 2023 and 2031.

2012 Air Quality Management Plan and Control Measure CMB-01

The SCAQMD developed and adopted the 2012 Air Quality Management Plan (AQMP) in partnership with CARB, U.S. EPA, SCAG and stakeholders throughout the region to outline the strategy to meet and maintain the state and federal air quality standards. The 2012 AQMP identified control measures needed to attain the federal 24-hour standard for PM2.5 by 2014 and provided updates on progress towards meeting the 8-hour ozone standard in 2023. Control Measure CMB-01 – Further NOx Reduction for RECLAIM is one of the control measures included in the 2012 AQMP. Control Measure CMB-01 called for a reassessment of BARCT for NOx RECLAIM facilities and estimated that a total of 2-3 tons per day (tpd) of NOx emission reductions could be achieved in 2014 for Phase I with an additional of 1-2 tpd NOx in 2020 for Phase II following the BARCT analysis. CMB-01 Phase I served as a PM2.5 SIP contingency measure for the 2012 AQMP, and if emission reductions were not needed in Phase I, the RTC reductions estimated for Phase I would be combined with the total reductions that could be achieved in Phase II. It was anticipated that NOx emissions reductions from both phases would also contribute to meeting the ozone standards in 2024 and 2032.

Current Emissions and RTC Holdings

The 2011 audited actual emissions were 20 tons per day (tpd) for the RECLAIM universe (59% from the refineries and 41% from the non-refinery sector). For ~~electrical~~ electricity generating facilities, staff used 2012 emissions instead of 2011 due to several reasons: 1) local ~~electrical~~ electricity generating facilities in the region operated more in 2012 to make up for the closure of the San Onofre Nuclear Generation Station (SONGS), 2) the commissioning of new ~~electrical~~ electricity generating facilities in the region was reflected more accurately in 2012, and 3) a recent shift in the use of renewable energy sources, such as wind, solar, and water, and their inherent intermittency resulted in the use of peaking units with increased numbers of startups and associated emissions. The 2011/2012 baseline emissions for the NOx RECLAIM universe in this analysis were 20.7 tpd.

The RECLAIM Trading Credit (RTC) holdings for the RECLAIM universe were 26.5 tpd, of which the refinery sector held 51% of the RTCs, ~~electrical~~ electricity generating facilities 21%, investors 4% and other RECLAIM facilities 24%.

Proposed BARCT, Emission Reductions, and RTC Reductions

The BARCT analysis resulted in the BARCT levels and incremental emission reductions by 2023 shown in Table EX.1. For the refinery sector, a new level of BARCT is proposed for fluid catalytic cracking units, boilers/heaters >40 mmbtu/hr, gas turbines, coke calciners, and sulfur recovery and tail gas incinerators. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal melting furnaces >150 mmbtu/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for ~~electrical~~ electricity generating facilities.[1]

Table EX. 1 - Summary of Proposed BARCT (May 2015)

Refinery Sector	2015 BARCT Level	Incremental Emission Reductions from 2000/2005 BARCT (tpd)
Fluid Catalytic Cracking Units	2 ppmv at 3% O2	0.43
Refinery Boilers and Heaters >40 mmbtu/hr	2 ppmv or 0.002 lb/mmbtu	0.94
Refinery Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
Sulfur Recovery Units Tail Gas Incinerators	2 ppmv at 3% O2 or 95% reduction	0.32
	Total	**6.00**

Non-refinery Sector	2015 BARCT Level	Incremental Emission Reductions from 2000/2005 BARCT (tpd)
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Metal Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
Internal Combustion Engines (non-OCS)	11 ppmv at 15% O2	0.84
Cement Kilns	0.5 lbs/ton	1.29 (note)
	Total	**2.77**

Note: The 1.29 tpd emission reductions from cement kilns were not included in the 2.77 tpd emission reductions because the cement facility was not in operation in 2011. Cement kilns were the highest emitting stationary source of NOx emissions in 2008, thus staff conducted a BARCT analysis for cement kilns and reduced the remaining emissions projected to the 2023 level for the cement facility to the BARCT level.

[1] Staff conducted a BARCT analysis focusing on the top 37 NOx emitting facilities in 2011, and a cement plant which was the highest NOx emitting stationary source in 2008. The BARCT analyses with detailed information are in the appendices (Appendices A-J of Part I for the refinery sector, and Appendices M-S of Part II for the non-refinery sector.)

As shown in Table EX.1, the total BARCT-equivalent emission reductions are 8.8 tpd (6.00 tpd for the refinery sector and 2.77 tpd for the non-refinery sector.) Due to projected growth,[2] the remaining emissions in 2023 at these proposed 2015 BARCT levels would be 10.2 tpd (2.76 tpd for the refinery sector and 7.47 tpd for the non-refinery sector.) Staff has added a 10% compliance margin to the 2023 remaining emissions. In addition, staff has added the remaining emissions from shutdown glass and cement facilities at BARCT levels, thereby adding to the compliance margin, as well as the emissions for new facilities entering RECLAIM program since 2005 to the total remaining emissions. Staff has provided some adjustments to account for uncertainties that arose in the BARCT analysis and for additional 2011 activity level adjustment. This results in total proposed NOx RTC reductions of 14 tpd from the current RTC holdings of 26.5 tpd in 2023.[3] The remaining RTCs for the NOx RECLAIM universe would be 12.5 tpd (26.5 tpd – 14 tpd = 12.5 tpd), which is 2.3 tpd or almost ~~23~~22.5% above the projected remaining emissions from RECLAIM NOx sources in 2023. See Figure EX.1.

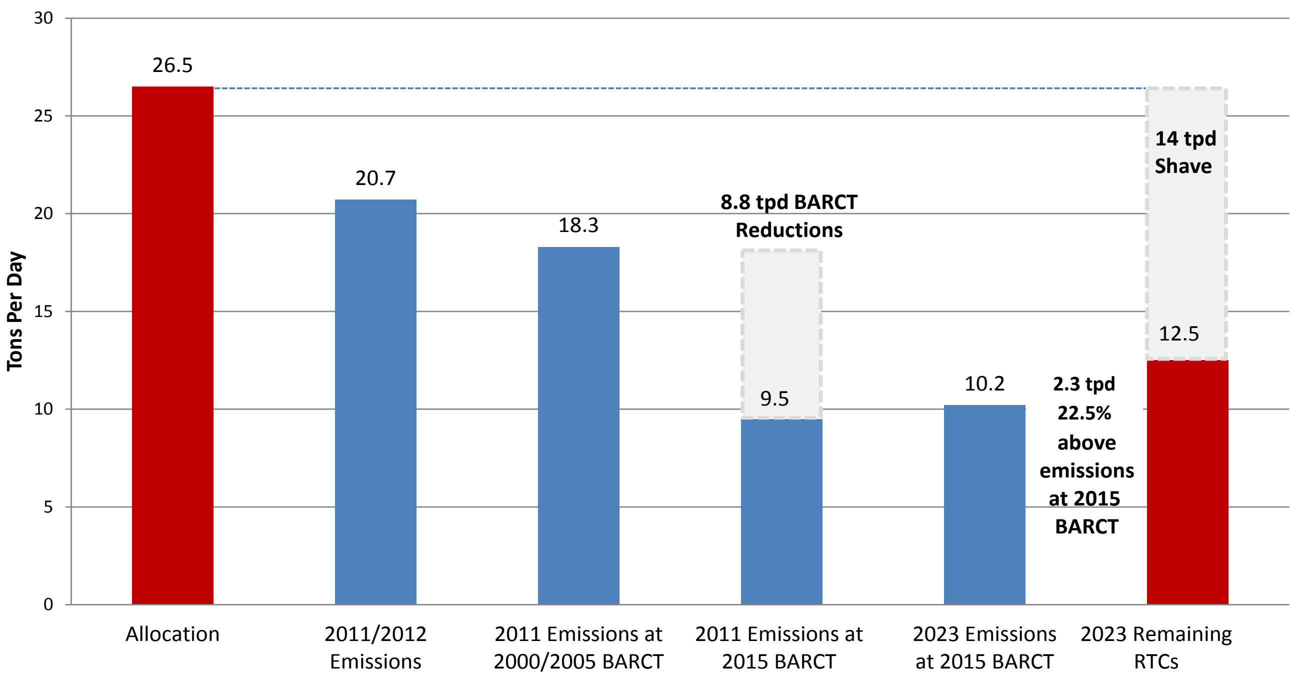

Figure EX. 1 – Audited Emissions and RTC Holdings

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[2] The growth factor for the refineries is 1. Electric generating facilities are expected to be more efficient with growth factor of 0.89 (2014 California Gas Report). The average growth factor for other non-refinery facilities is 1.1 (Southern California Association of Government (SCAG)).

[3] RTC Reductions = RTC Holdings – Remaining Emissions in 2023 - Adjustments = 14 tpd. Refer to Chapter 5 and Appendix U of Part III for detailed information.

Staff is proposing to distribute the 14 tpd NOx RTC reductions to 56 facilities and investors that hold 90% of the 26.5 tpd RTCs. Investors are grouped with the refineries and treated as a facility for shave purposes. The remaining 219 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was limited or no new BARCT for the types of equipment and operation at these facilities.[4] Staff's current proposal is to weight the amount of shave considering the technology available to different facility types as summarized below:

66% shave for 9 refineries and investors
49% shave for 21 ~~electrical~~ electricity generating facilities
49% shave for 26 other major facilities
0% shave for 219 remaining facilities

The 2023 remaining emissions after installing BARCT, the RTC holdings after the shave, and the surplus or deficit RTCs after the shave for each industry sector are presented in Table EX.2. After the shave, the 9 refineries, the investors, and the 21 ~~electrical~~ electricity generating facilities would have surplus RTCs. Some facilities in the 26 non-~~electrical~~ electricity generating facilities and the 219 remaining facilities would not be subject to any shave however their emissions would grow above the RTC holdings that they currently have and they would have to purchase RTCs from other industry sectors to reconcile their projected emissions. Overall, there is a net of 2.3 tpd surplus RTCs for the entire RECLAIM universe.

Table EX. 2 – Summary of 2023 RTC Holdings and 2023 Emissions After BARCT

	9 Refineries	**15 Investors**	**21 ~~Electrical~~ Electricity generating facilities**	**26 Non-~~Electrical~~ Electricity generating facilities**	**219 Other Facilities**	**Net Total**
Current RTC Holdings (tpd) (note)	14.15	0.42	5.63	3.45	2.86	26.5
% Shave	66%	66%	49%	49%	0%	
RTC Holdings After Shave (tpd)	4.81	0.14	2.87	1.76	2.86	12.5
2023 Emissions After BARCT (tpd)	2.76	0	2.04	1.93	3.5	10.2
Surplus or Deficit RTCs (tpd)	2.05	0.14	0.83	(0.17)	(0.64)	2.3

Note: RTC Holdings as of September 22, 2015

Staff is proposing to implement the 14 tpd RTC reductions over a 7-year period from 2016 to 2022 but as expeditiously as possible to help the Basin meet the PM2.5 standard deadlines as well as the ozone standards in 2023 and 2031. Staff is proposing the following implementation schedule for NOx RTC reductions:

2016 – 4 tons per day

[4] The ICEs and small boilers or heaters in the remaining 219 facilities could be subject to additional BARCT but the potential emission reductions totaled less than 0.1 tpd.

2018 – 2 tons per day
2019 – 2 tons per day
2020 – 2 tons per day
2021 – 2 tons per day
2022 – 2 tons per day

Over the past five years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5 tpd to 8 tpd. Staff is proposing a 4 tpd RTC reduction in 2016. Additional BARCT implementation will take about 2 - 4 years for planning, permitting, and construction, and thus staff is proposing the remaining shave of 10 tpd to take place over five years from 2018 to 2022.

The BARCT analyses are described in Chapter 3, the costs and cost effectiveness of the proposal are described in Chapter 4 and are summarized in Table EX.3. The total Present Worth Values (PWVs) of the project range from $728 M to $1.1 B, and the overall cost effectiveness values of the project as a whole range from $9 K to $14 K per ton NOx reduced. Individual category cost-effectiveness is set forth in the table below. The RTC reductions are estimated in Chapter 5, and the proposed changes in rule language are described in Chapter 6.

Table EX. 3 - Summary of Costs and Cost Effectiveness

	2015 BARCT	Incremental Emission Reductions from 2000/2005 BARCT (tpd)	Number of Affected Facilities	Estimated No of Control Devices	PWVs ($M)	Incremental Cost Effectiveness (thousand dollars/ton)
Refinery Sector						
FCCUs	2 ppmv	0.43	5	5 SCRs (or 2 SCRs + 3 LoTOx/WGS)	152 - 391	3 - 13
Boilers and Heaters	2 ppmv	0.94	8	~~75~~ 73 SCRs	237	28
Refinery Gas Turbines	2 ppm	4.14	5	7 SCRs and adding catalysts to 4 SCRs	53 - 98	1 - 3
Coke Calciner	10 ppmv	0.17	1	1 UltraCat (or 1 LoTOx/WGS)	40 - 91	22 - 35
SRU/TG Incinerators	2 ppmv	0.32	4	6 SCRs (or 1 SCRs + 5 LoTOx/WGS)	83 - 106	28 - 40
Refinery Total		**6.00**		**~~92~~ 91 SCRs + 1 UltraCat (or ~~84~~ 83 SCRs and 9 LoTOx/WGS) and adding catalysts to SCRs**	**565 - 923**	**10 - 17**
Non-Refinery Sector						
Glass Melting Furnaces	80% red	0.24	1	2 SCRs (or 1 UltraCat)	6 - 15	3 - 7
Sodium Silicate Furnace	80% red	0.09	1	1 SCR (or 1 UltraCat)	3 - 5	4 - 8
Metal Heat Treating	9 ppmv	0.56	1	1 SCR	8 - 10	3 - 4
Gas Turbines (non-OCS)	2 ppmv	1.04	3	14 SCRs	~109	5 - 36
ICEs (non-OCS)	11 ppmv	0.84	7	16 SCRs	~37	5 - 8

Non-Refinery Total (w/o Cement Kilns)	**2.77**		**34 SCRs (or 31 SCRs and 2 UltraCat)**	**163 - 176**	**6 - 7**
Overall	**8.8**		**~~127~~ 125 SCRs + 1 UltraCat (or ~~115~~ 114 SCRs + 9 LoTOx/WGS + 2 UltraCat)**	**728 - 1099**	**9 - 14**

Public Process

The public process for PAR XX – NOx RECLAIM is summarized in Table EX.4. Staff began this rulemaking process in the 4th quarter 2012. In 2013, staff formed a RECLAIM Working Group to discuss potential amendments to the NOx RECLAIM program that included members representing NOx RECLAIM facilities, the Western States Petroleum Association (WSPA), the environmental community, as well as CARB and U.S. EPA. The first meeting was conducted on January 31, 2013. A list of participants is shown in Table EX.5.

To gather pertinent information for rule development, staff sent out Survey Questionnaires to 38 facilities, including the top 37 emitting facilities in 2011 and a cement facility which was the highest NOx stationary emission sources in 2008. Since January 2013, ~~eleven~~ *fourteen* Working Group Meetings were held to discuss potential BARCT levels for major NOx sources ~~at the top 37 and cement facilities~~, the emissions inventory, potential for emission reductions, and proposals for RTC reductions.[5] In addition, in September 2014, SCAQMD staff contracted with two consultants (Environmental Technology Services, Inc. (ETS) and Norton Engineering Consultants Inc. (NEC)) to conduct independent BARCT analyses. The consultants and staff visited a glass manufacturing facility, a cement manufacturing facility, and six refineries to assess the availability of space for the installation of additional controls and to discuss BARCT issues and concerns with the stakeholders. The consultants completed their analyses in December 2014, and staff held the 8th Working Group Meeting in January 7, 2015 to report on the consultants' findings to the stakeholders. A CEQA and Socioeconomic scoping session was held in January 8, 2015 and staff received ten comment letters. From January to March 2015, staff reviewed the consultants' analyses and addressed comments received in response to the CEQA and Socioeconomic scoping session. Staff also extended the contract for NEC to allow time to produce the confidential proprietary information reports for each refinery, and this task was completed in April 2015.

In addition to the ~~twelve~~ fourteen Working Group Meetings, staff participated in over ~~30~~ *50* meetings *held* with various stakeholders individually or in groups to discuss the BARCT analysis and the proposed allocation reduction distribution (shave) methodology. Staff also met with a

[5] The Survey Questionnaires for the refineries and non-refineries are in Appendix L and Appendix T, respectively. The detailed BARCT analyses are in the relevant appendices (Appendices A-J for refinery sector and Appendices M-S for non-refinery sector.) Staff focused on the top 37 emitting facilities contributing more than 85% of the 2011 emissions and the cement plant which was the highest NOx stationary emission source in 2008. Staff looked at other sources in the remaining facilities: the emission reductions from ICEs and small boilers and heaters at these facilities would generate less than 0.1 tpd emission reductions and staff did not identify any more stringent BARCT for other equipment at these facilities.

number of air pollution control manufacturers to discuss control technologies, and invited the manufacturers to write manuscripts and give presentations at the 2014 Air & Waste Management Association annual conference in Long Beach. Several refinery representatives participated in the discussions at the conference.

A Public Workshop was conducted on July 22, 2015, a Public Consultation Meeting was conducted on September 29, 2015, the draft Program Environmental Assessment was released on August ~~13~~14, 2015 for 75 days public comments, and the draft socioeconomic analysis was released on September 9, 2015. ~~Three~~ Four Stationary Source Committee meetings were held on March 21, 2014, July 24, 2014, ~~and~~ October 14, 2015, and November 20, 2015 including a special session requested by industry devoted to RECLAIM discussion. The Public Hearing is scheduled for ~~November 6~~December 4, 2015.

Table EX. 4 - Summary of Public Process

Calendar Year 2013	
January 31, 2013	RECLAIM Working Group was formed. The 1st RECLAIM Working Group Meeting was conducted
March 20, 2013	2nd RECLAIM Working Group Meeting
June 13, 2013	3rd RECLAIM Working Group Meeting. Staff conducted a Survey to gather information for rule development.
September 19, 2013	4th RECLAIM Working Group Meeting
Calendar Year 2014	
January 22, 2014	5th RECLAIM Working Group Meeting
March 18, 2014	6th RECLAIM Working Group Meeting
March 21, 2014	1st Stationary Source Committee Meeting
July 31, 2014	7th RECLAIM Working Group Meeting
September 2014 – December 2014	Staff contracted ETS and NEC to conduct independent BARCT analyses for the non-refinery and refinery sectors. The consultants and staff visited facilities to discuss BARCT issues with the stakeholders and assess space availability. The consultants finalized their analyses and reports in December 2014.
Calendar Year 2015	
January 7, 2015	8th RECLAIM Working Group Meeting. Staff presented the results of the consultants' analyses to the Working Group Meeting.
January 8, 2015	A CEQA and Socioeconomic Scoping session was held. Ten (10) comment letters were received.
January – March	Staff conducted a review of the consultants' analyses and addressed the comments received in the CEQA and Socioeconomic Scoping sessions.

April 10, 2015	The contract for NEC was extended to separate confidential reports for the refineries. This task was completed April 10, 2015
April 29, 2015	9th RECLAIM Working Group Meeting
June 4, 2015	10th RECLAIM Working Group Meeting
July 9, 2015	11th RECLAIM Working Group Meeting
July 22, 2015	Public Workshop. Release Preliminary Draft Staff Report and Rule Language
July 24, 2015	2nd Stationary Source Committee Meeting
August ~~13~~14, 2015	Release Draft Program Environmental Assessment. Draft PEA commenting period extended to October 6, 2015
September 9, 2015	Release Draft Socioeconomic Report
September 23, 2015	3rd Stationary Source Committee Meeting 12th RECLAIM Working Group Meeting
September 29, 2015	Public Consultation Meeting
October 14, 2015	~~3rd~~ 4th Stationary Source Committee Meeting
November 20, 2015	5th Stationary Source Committee Meeting
November 23, 2015	13th RECLAIM Working Group Meeting
November 30, 2015	14th RECLAIM Working Group Meeting
~~November 6~~December 4, 2015	Public Hearing

Table EX. 5 - List of Participants

Organizations
California Council for Environmental and Economic Balance (CCEEB)
Earth Justice
Industry Coalition
Regulatory Flexibility Group (RegFlex)
Southern California Air Quality Alliance (SCAQA)
Western States Petroleum Association

Facilities
Air Products
California Portland Cement Company
Chevron
ExxonMobil
Owens Brockway
Paramount
Phillips66
Tesoro
Ultramar
Other facilities

Manufacturers of Control Devices & Consultants
BASF
BELCO
Cheng Low NOx
ClearSign
Cormetech
ETS
Elex CEMCAT
Grace Davidson
Great Southern Flameless
Haldor Topsoe
INTERCAT
MECS
Mitsubishi
NEC
Tri-Mer

Others
California Air Resources Board
California Independent System Operator (CalISO

Bay Area Air Quality Management District
Santa Barbara Air Pollution Control District
San Joaquin Valley Air Pollution Control District
U.S. Environmental Protection Agency

Chapter 1 – Background

Legislative Authority

The California Legislature created the SCAQMD in 1977 as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin). The H&SC requires the SCAQMD to adopt an AQMP outlining how the Basin will achieve and maintain state and federal ambient air quality standards by the earliest practicable date. In addition, the SCAQMD is required to adopt rules and regulations to implement the AQMP. The SCAQMD's rules and regulations must contain BARCT for existing sources. The SCAQMD staff is required to conduct a BARCT reassessment on a regular basis to capture the advancement in control technology and to ensure that RECLAIM facilities achieve the emission reductions that would have occurred under a command-and-control approach and that emission reductions from the program contribute to the Basin achieving the federal and state ambient air quality standards. The relevant H&S provisions, including a definition of BARCT, are cited below:

H&SC §40460(a): "*… the south coast district board shall adopt a plan to achieve and maintain the state and federal ambient air quality standard.*"

H&SC §40440(a): "*The south coast district board shall adopt rules and regulations that carry out the plan and are not in conflict with state law and federal laws and rules and regulations*."

H&SC §40440(b)(1): "*~~-~~The rules and regulations adopted … shall … require the use of best available control technology for new and modified sources and the use of best available retrofit control technology for existing sources*."

H&SC §40406: "*…best available retrofit technology means an emission limitation that is based on the maximum degree of reduction achievable taking into account environmental, energy, and economic impacts by each class or category of source.*"

Non-Attainment Status

Relative to the ozone and PM2.5 NAAQS promulgated by the U.S. EPA to protect public health and the environment, the Basin is currently classified as an "extreme" non-attainment area for ozone and is a non-attainment area for annual and 24-hour PM2.5. Scientific studies have found an association~~s~~ between exposure to particulate matter and ozone and significant health problems, including asthma, chronic bronchitis, reduced lung function, irregular heartbeat, heart attack, and premature death in people with heart or lung disease. Individuals particularly sensitive to air pollution exposure include older adults, people with heart and lung disease, and children.

There are six criteria pollutants that contribute to ambient air pollution for which there are federal NAAQS: ozone, carbon monoxide, lead, particulate matter, sulfur dioxide, and nitrogen dioxide. The effect of reducing emissions of each of these pollutants varies by area depending on the composition of the atmosphere, concentrations of these pollutants and other area-specific factors. The federal EPA requires the SCAQMD to implement all reasonably available control measures (RACM) and reasonably available control technology (RACT) considering economic and technical feasibility and other factors to reduce criteria air pollutants.

On March 12, 2008, the EPA strengthened its ground-level 8-hour ozone standard from 0.08 ppm to a level of 0.075 ppm. On May 21, 2012, the EPA classified two areas in the country, the South Coast and the San Joaquin Valley, as "Extreme" non-attainment areas with respect to the 2008 8-hour ozone standard. The attainment dates for the 1997 and 2008 ozone standards are June 15, 2024 and July 20, 2032, respectively, with emission reductions and attainment required in the previous calendar year. NOx is a major precursor of ozone and PM2.5, and reducing NOx is essential for the Basin to attain the ozone ambient air quality standards while also helping to meet PM2.5 standards. The SCAQMD staff is currently developing the 2016 AQMP to address ozone and PM2.5 attainment strategies.

Control Measure CMB-01 of the 2012 AQMP

Control Measure CMB-01 – *Further NOx Reductions from RECLAIM* is one of the control measures specified in the 2012 AQMP. The control measure CMB-01 has 2 phases: Phase I has an estimated reduction of 2–3 tpd NOx and serves as a contingency measure for PM2.5 attainment. A contingency measure is a measure that will be automatically implemented if the basin fails to meet the PM2.5 standards by the attainment date. Based on recent data, the Basin will fail to meet the 24-hour PM2.5 ambient air quality standard by the original attainment date of 2014 as well as the revised attainment date of 2015. Therefore, the SCAQMD has asked EPA to reclassify the Basin as "serious" non-attainment for the 24-hour standard, and will be required to submit a new attainment plan. If Phase I was not triggered, CMB-01 anticipated that Phase I reductions would be rolled into Phase II to help attain the ozone standards. In combination, Phase I and Phase II together had estimated reductions of 3-5 tpd with the lower end of emission reduction range committed to in the State Implementation Plan (SIP) yet to be acted on by U.S. EPA. The adoption date and implementation date for Control Measure CMB-01 were estimated to be 2015 and 2020, respectively. The analysis done for these amendments resulted in significantly more reductions than those identified in the control measure. The control measure emission reduction estimates are based on information available at that time, and the emission reductions proposed for a rule that implements a control measure can be more or less than the control measure estimate based on additional analysis of available cost effective technologies. The control measure CMB-01 mentioned that additional reductions would be sought if required to implement BARCT, and that all feasible reductions are needed to attain the ozone standards.

Current NOx RECLAIM Program

On October 15, 1993, the SCAQMD's Governing Board adopted the RECLAIM program and Regulation XX. Regulation XX includes 11 rules that specify the applicability, NOx and SOx allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements. The RECLAIM program started with 392 NOx facilities in 1993, dropped to 281 facilities in 2011, with 275 facilities by end of the 2013 compliance year. Under the RECLAIM program, facilities are issued SOx and NOx annual allocations, also known as facility caps. The facility caps decline annually to reflect the levels of BARCT that were envisioned to be in place at the RECLAIM facilities. To meet their annual declining allocations, RECLAIM facilities have the flexibility of installing pollution control equipment, changing operations, or purchasing RECLAIM Trading Credits. It was envisioned that a BARCT analysis would be conducted periodically to capture the advancement in control technology and to assure that the RECLAIM program would achieve emission reductions equivalent to command and control approaches and as expeditiously as possible. Throughout the years, there have been a number of amendments to the RECLAIM rules, including BARCT reassessments for NOx in 2005 and SOx in 2010. As a result of the January 2005 amendment, NOx RTCs were reduced by 7.7 tpd, approximately 22.5%, applied all 281 RECLAIM facilities. This reduction was implemented in phases: 4 tpd by 2007 and an additional 0.925 tpd in each of the following 4 years. Figures 1.1 - 1.3 show the historical trend of NOx emissions, RTC allocations, and RTC price for compliance years 1994 - 2013 reflecting the fact that the NOx reductions specified by the January 2005 amendment did not upset the market or cause RTC prices to rise above the $15,000 per ton, which is the level specified in Rule 2015 that would require a program review.

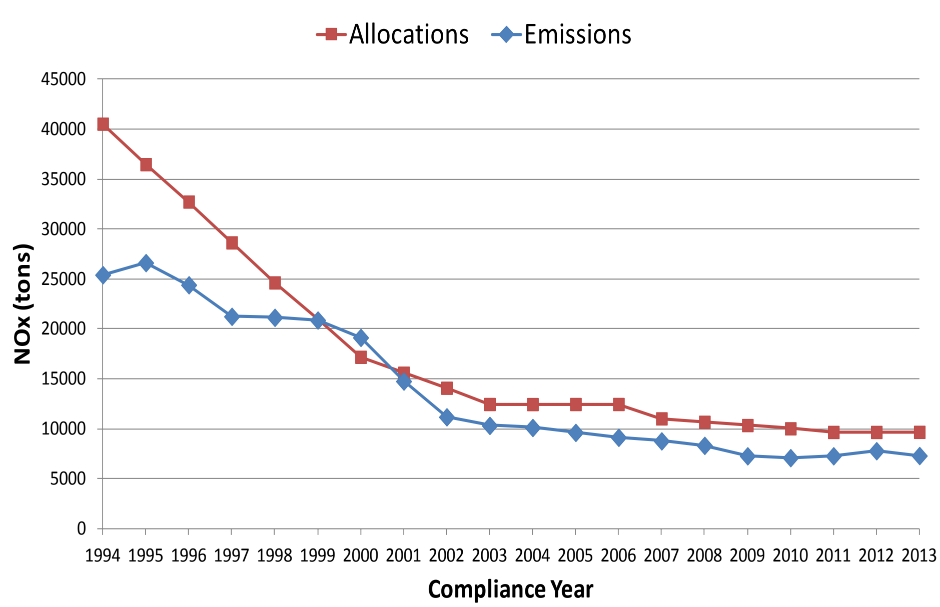


Figure 1. 2 – Audited Emissions and RTC Holdings

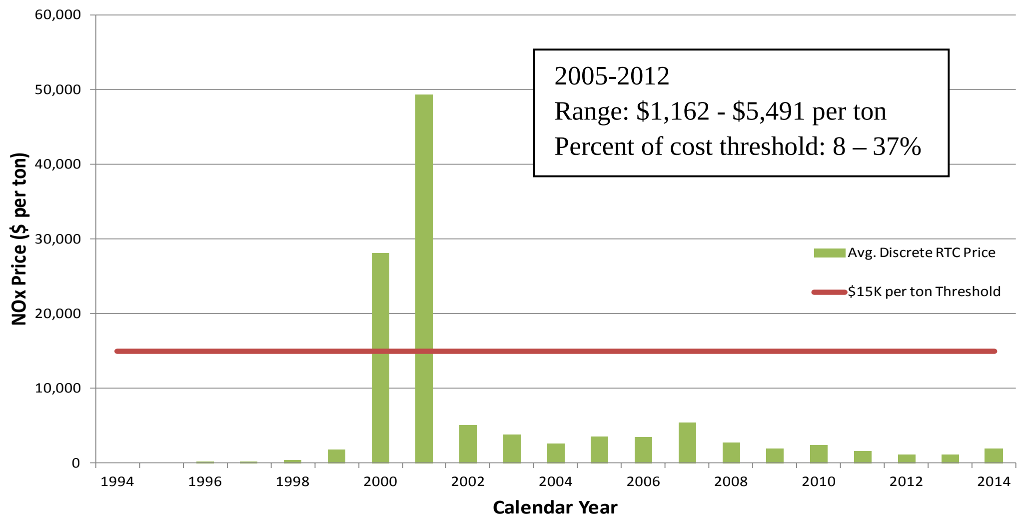
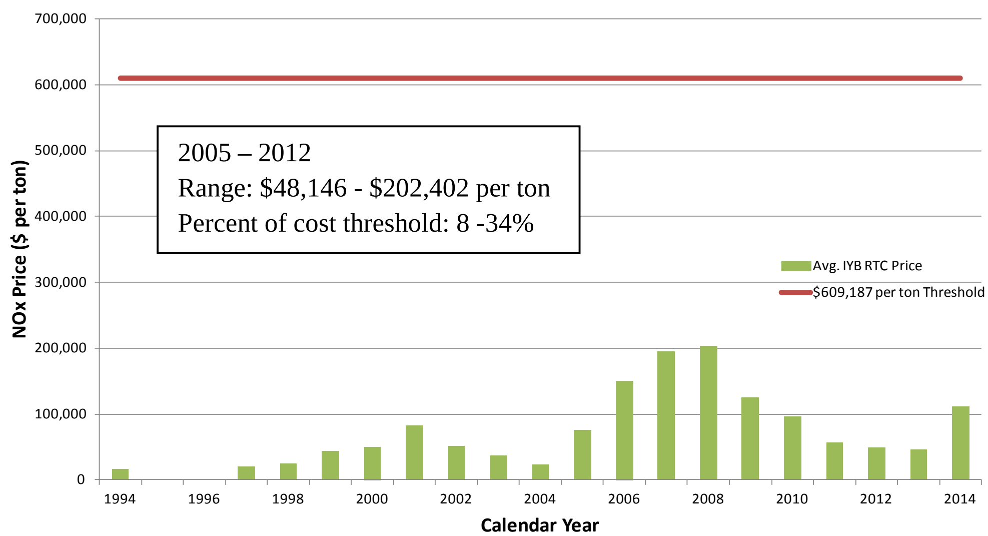


Figure 1.3 – NOx Discrete RTC Price versus Threshold



Note: IYB cost threshold is adjusted annually by CPI

Figure 1.4 – NOx Infinite Year Block (IYB) RTC Price versus Threshold

According to the RECLAIM Annual Audit Reports, the vast majority of the RECLAIM facilities complied with their NOx RTC allocations and their aggregate RECLAIM NOx emissions remained below their NOx allocations for each compliance year since 2005. RECLAIM facilities had a high rate of compliance for covering emissions with RTCs. The same was true for all other years of the program except for 2000 and 2001 when there was a California power crisis. The audited annual NOx emissions, NOx RTCs allocated for the universe, and unused RTCs are summarized in Table 1.1. Data show that approximately 21–30% RTCs in each of the past 5 years were not used, approximately 5.45 tpd – 8.41 tpd.

Table 1. 1 – Audited Emissions, RTC Holdings and Unused RTCs from 2009-2013

Compliance Year	Audited emissions (tons)	RTC Holdings (tons)	Unused RTCs (tons)	Unused RTCs (%)
2009	7,306	10,377	3,071	30%
2010	7,121	10,053	2,932	29%
2011	7,302	9,690	2,388	25%
2012	7,691	9,689	1,988	21%
2013	7,326	9,699	2,373	24%

Reference: Table 3-2, page 3-4, Annual RECLAIM Audit Report for 2013 Compliance Year

NOx RECLAIM Facilities

There were ~~281~~ *276* facilities in RECLAIM as of June 2011 and 275 by the end of compliance year 2013. These facilities either elected to enter the program or had NOx emissions greater than or equal to four tons per year in 1990 or any subsequent year. The distribution of the 20 tpd audited 2011 emissions and the 26.5 tpd RTC allocations for 2020 are shown in Figures 1.5 and 1.6.

The top 37 facilities emitted 17.10 tpd NOx in 2011, more than 85% of emissions. The NOx emissions from RECLAIM facilities are generated from a wide range of equipment, and the top NOx emitting sources at the 37 facilities are refinery coke calciners, refinery fluidized catalytic cracking units, refinery and non-refinery gas turbines, refinery boilers and heaters, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces, internal combustion engines, and refinery sulfur recovery and tail gas incinerators. Cement kilns were the highest emitting stationary NOx source in 2008. The 2011 inventory did not include the cement kilns in the inventory since they were non-operational and subsequently shut down in 2012. However staff did identify a new BARCT level for this operation and removed the equivalent amount of emissions from the remaining emissions in 2023 from the cement kiln.

Figure 1.6 shows the amount of RTC holdings by sector for Compliance Year 2020 without considering 2015 BARCT levels and the proposed amendments. Refineries hold over half of the RTCs with the second most predominant RTC holding industry being ~~electrical~~ electricity generating facilities.

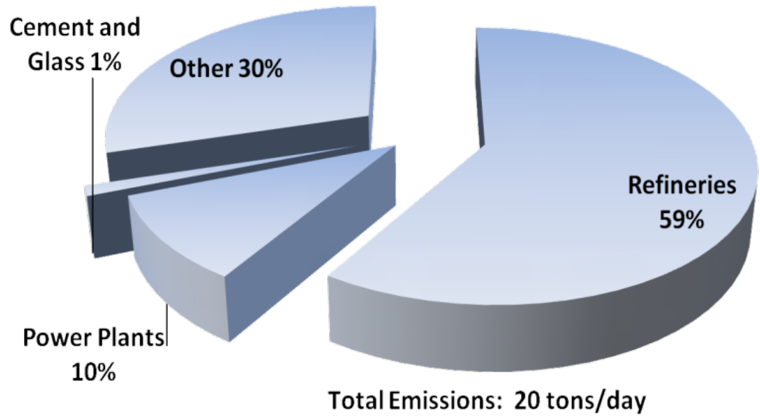


Figure 1. 5 – Distribution of 20 tpd NOx Emissions (End of Compliance Year 2011)

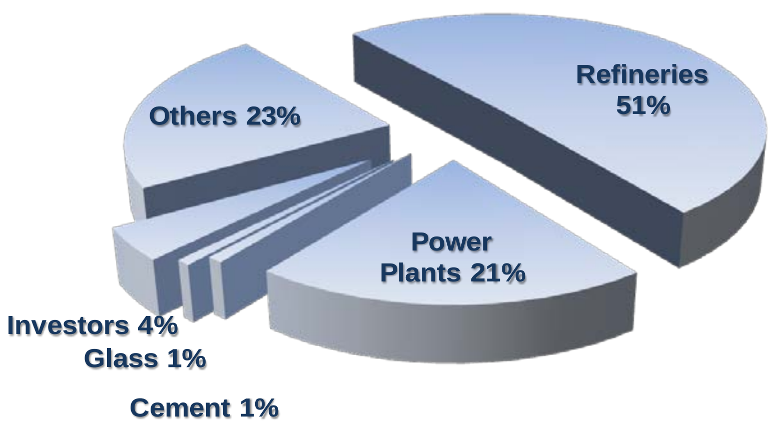


Figure 1. 6 – Distribution of 26.5 tpd RTC Holdings (End of Compliance Year 2020)

Chapter 2 – Facility Emissions and RTC Holdings

Projected Emissions and Emission Reductions

As stated in the 2012 AQMP and summarized in Table 2.1 below, NOx emissions from the RECLAIM facilities were projected to be about 27 tpd by 2023 (26.51 tpd total allocation rounded up to 27 tpd in the 2012 AQMP), representing 37% of the NOx emissions from stationary sources. Collectively, RECLAIM is the fourth largest source of NOx emissions in the Basin in 2023 as shown in Table 2.2.

The 3-5 tpd of reductions for CMB-01 were estimated during the development of the 2012 AQMP, however staff's analysis of BARCT shows that additional reductions from RECLAIM NOx sources are possible. Staff is proposing that the RECLAIM program can contribute 14 tpd additional NOx emissions reductions by 2023.

Table 2. 1 - Annual Average Emissions (tpd) by Major Source Category (2023 Base Year)

Source Category	**NOx**
Stationary Sources	
Fuel Combustion (non-RECLAIM)	27
Waste Disposal	2
Cleaning and Surface Coatings	0
Petroleum Production and Marketing	0
Industrial Processes	0
Solvent Evaporation	
Consumer Products	0
Architectural Coatings	0
Others	0
Misc. Processes	17
RECLAIM Sources	**27**
Total Stationary Sources	**73**
Total Mobile Sources	**255**
TOTAL	**328**

Reference: Table 3-6A, 2012 South Coast AQMP

Table 2. 2 - Top Ten Ranking of NOx Emissions from Highest to Lowest (2023 Base Year)

Rank	Sources
1	Heavy-Duty Diesel Trucks
2	Off-Road Equipment
3	Ships & Commercial Boats
4	NOx RECLAIM
5	Locomotives
6	Aircraft
7	Residential Fuel Combustion
8	Heavy-Duty Gasoline Trucks
9	Passenger Cars
10	Light-Duty Trucks

Reference: Table 3-10 of the 2012 South Coast AQMP

Audited Facility Emissions and RTC Allocations

The ~~281~~ *276* RECLAIM facilities, as of June 2011, emitted 20.0 tpd NOx in 2011 adjusted to 20.7 tpd NOx using the ~~electrical~~ electricity generating facilities' emissions in 2012 instead of 2011 emissions. Table 2.3 below lists the top 37 emitting facilities that contributed 17.10 tpd NOx emissions in 2011, more than 85% of the emissions from the entire NOx RECLAIM universe. The cement facility, the highest emitting NOx facility from 2008 to 2010, was not in operation in 2011.

At the beginning of the RECLAIM program, the NOx RECLAIM universe was granted 40,534 tons per year (111 tpd) RTCs. This original amount of RTCs gradually dropped to a level of 12,486 tons per year (34.2 tpd) in 2005. In 2005, the RECLAIM rules were amended to implement a BARCT assessment that resulted in a cumulative RTC reduction of 7.7 tpd that was fully implemented in 2011. For compliance year 2011 and beyond, the RTC holdings for the NOx universe remain at a constant level of 9,677 tons per year (26.5 tpd).

Table 2. 3 - NOx Audited Emissions (2011 Compliance Year)

			2011 Emissions (lbs)	2011 Emissions (tpd)
1	800089	EXXONMOBIL OIL CORPORATION	1,602,233	2.19
2	800030	CHEVRON PRODUCTS CO.	1,425,393	1.95
3	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1,231,852	1.69
4	800436	TESORO REFINING AND MARKETING CO, LLC	1,171,965	1.61
5	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1,143,902	1.57
6	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	673,652	0.92
7	800026	ULTRAMAR INC (NSR USE ONLY)	534,363	0.73
8	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	407,394	0.56
9	800183	PARAMOUNT PETR CORP (EIS USE)	104,249	0.14
10	151798	TESORO REFINING AND MARKETING CO, LLC	93,488	0.13
		Total Refineries		**11.49**
1	46268	CALIFORNIA STEEL INDUSTRIES INC	464,990	0.64
2	800128	SO CAL GAS CO (EIS USE)	461,243	0.63
3	166073	BETA OFFSHORE	391,977	0.54
4	171960	TIN, INC. DBA INTERNATIONAL PAPER	327,637	0.45
5	18931	TAMCO	226,012	0.31
6	800074	LA CITY, DWP HAYNES GENERATING STATION	205,022	0.28
7	160437	SOUTHERN CALIFORNIA EDISON	204,132	0.28
8	800193	LA CITY, DWP VALLEY GENERATING STATION	166,413	0.23
9	4242	SAN DIEGO GAS & ELECTRIC	142,751	0.20
10	4477	SO CAL EDISON CO	137,290	0.19
11	7427	OWENS-BROCKWAY GLASS CONTAINER INC	135,486	0.19
12	119907	BERRY PETROLEUM COMPANY	131,857	0.18
13	129816	INLAND EMPIRE ENERGY CENTER, LLC	105,857	0.15
14	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	103,988	0.14
15	115389	AES HUNTINGTON BEACH, LLC	98,993	0.14
16	51620	WHEELABRATOR NORWALK ENERGY CO INC	89,025	0.12
17	5973	SO CAL GAS CO	88,258	0.12
18	11435	PQ CORPORATION	81,270	0.11
19	115394	AES ALAMITOS, LLC	80,929	0.11
20	800335	LA CITY, DEPT OF AIRPORTS	73,245	0.10
21	129497	THUMS LONG BEACH CO	66,364	0.09
22	124838	EXIDE TECHNOLOGIES	62,824	0.09
23	15504	SCHLOSSER FORGE COMPANY	52,331	0.07
24	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49,983	0.07
25	800330	THUMS LONG BEACH	49,657	0.07
26	114801	RHODIA INC.	48,878	0.07
27	22911	CARLTON FORGE WORKS	48,839	0.07
		Total non-refineries		**5.61**
		Total for top 37 emitting facilities		**17.10**

Major NOx Sources at Top Emitting Facilities

RECLAIM Rule 2012 establishes the requirements for monitoring, reporting and recordkeeping of NOx emissions under the RECLAIM program and classifies the NOx emitting equipment at the RECLAIM facilities into three categories: major NOx sources, large NOx sources, and NOx process units. RECLAIM facilities are required to monitor the emissions for each major NOx source with a Continuous Emissions Monitoring System (CEMS) and report the emissions electronically on a daily basis via a remote terminal unit to the SCAQMD Central Station. The emissions for each large source are calculated based on fuel usage or exhaust gaseous flow rates and reported electronically on a monthly basis to the SCAQMD Central Station. The emissions from all process units are reported on a quarterly basis.

Table 2.4 shows that major NOx sources contributed 88% of the NOx emissions from the NOx RECLAIM universe; large NOx sources and process units generated only 12% of the NOx RECLAIM emissions. Thus, staff focused on the major NOx sources at the top 37 emitting facilities to evaluate potential BARCT and emission reductions.

The major NOx sources at the top 37 emitting RECLAIM facilities subject to new 2015 BARCT analysis are refinery fluid catalytic cracking units, refinery boilers and heaters >40 mmbtu/hr, refinery and non-refinery gas turbines, cement kilns, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces >150 mmbtu/hr, refinery sulfur recovery and tail gas incinerators, and internal combustion engines.

Table 2. 4 - NOx Emissions per Source Classification

Source Categories	NOx (tons per day)	Number of Equipment	Percentage of Emissions
Major NOx Sources	17.5	415	88%
Large sources and Process Units	2.6	>1000	12%
Total	**20.0**		**100%**

Chapter 3 – 2015 Proposed BARCT and Emission Reductions

Previous BARCT Determinations

At the inception of the RECLAIM program, NOx starting allocations for 1994 and ending allocations for 2000 were based on the starting and ending emissions factors listed in Table 1 of Rule 2002 – *Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).* For the 2003 ending allocations, 2000 ending allocations were adjusted to be equal to the 1991 AQMP projected inventory for RECLAIM sources in 2003. The 2005 future year allocations were set equal to the 2003 allocations. In 2005, the SCAQMD staff conducted a BARCT assessment, and the rules were amended to reduce the RTCs by 7.7 tpd implemented by 2011. Table 3 of Rule 2002 was added to record the 2005 BARCT levels. The BARCT levels were kept at the 2000 ending emission factors as shown in Table 2 of Rule 2002 for individual equipment categories where improved control technologies were not yet deemed applicable or cost-effective in the 2005 BARCT assessment.

Proposed 2015 BARCT

Staff is proposing the BARCT levels tabulated in Table 3.1 and estimating that these 2015 BARCT levels will provide about 8.8 tpd in NOx emission reductions (6.00 tpd for refinery sector and 2.77 tpd for non-refinery sector) beyond what could be achieved by the 2005 BARCT levels for each category of major emitting sources at the top emitting facilities. Further discussions of NOx control technologies, proposed BARCT levels, estimated emission reductions, costs and cost effectiveness values are discussed in Part I of this staff report for the refinery sector and Part II for the non-refinery sector. The RTC reductions to implement BARCT are 14 tpd. See Chapter 5 and Part III of this staff report.

Part I – BARCT Analyses for Refinery Sector:

Appendix A	Fluid Catalytic Cracking Units
Appendix B	Boilers and Heaters, >40-100 mmbtu/hr
Appendix C	Refinery Gas Turbines
Appendix D	Coke Calciner
Appendix E	Sulfur Recovery Units Tail Gas Incinerators

Part II – BARCT Analyses for Non-Refinery Sector:

Appendix M	Cement Kilns
Appendix N	Container Glass Melting Furnaces
Appendix O	Sodium Silicate Furnace

Appendix P	Metal Melting Furnaces > 150 mmbtu/hr
Appendix Q	Non-Refinery Gas Turbines
Appendix R	Non-Refinery, Non-~~Electrical~~ Electricity Generating Facility Internal Combustion Engines
Appendix S	Non-Refinery Boilers > 40 mmbtu/hr

Table 3. 1 - 2015 Proposed BARCT Levels and Emission Reductions

Refinery Sector	2015 BARCT Level	Incremental Emission Reductions Beyond 2000/2005 BARCT (tpd)
Fluid Catalytic Cracking Units	2 ppmv at 3% O2	0.43
Boilers and Heaters >40 mmbtu/hr	2 ppmv or 0.002 lb/mmbtu	0.94
Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
Sulfur Recovery Units Tail Gas Incinerators	2 ppmv at 3% O2 or 95% reduction	0.32
	Total	**6.00**

Non-refinery Sector	2015 BARCT Level	Incremental Emission Reductions Beyond 2000/2005 BARCT (tpd)
Cement Kilns	0.5 lb/ton clinker	1.29 (note)
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
ICEs (non-OCS)	11 ppmv at 15% O2	0.84
	Total	**2.77**

Note: The 1.29 tpd emission reductions from cement kilns were not included in the 2.77 tpd emission reductions because the cement facility was not in operation in 2011. Cement kilns were the highest source of NOx emissions in 2008, thus staff conducted a BARCT analysis for cement kilns and reduced the remaining emissions projected to the 2023 level for the cement facility to the BARCT level.

Co-Benefits of Energy Efficiency Projects

For the refinery sector, in addition to the 6.00 tpd emission reductions shown in Table 3.1, there are about 0.6 to 0.7 tpd NOx emission reductions that are expected to have occurred concurrently with the energy efficiency projects to reduce greenhouse gases as shown in Table 3.2. According to CARB staff, these co-benefits reductions were not yet included in the baseline and SCAQMD staff did not include the co-benefits in this proposal. See Appendix K for further details.

Table 3. 2 - Co-Benefits of Emission Reductions for Energy Efficiency Projects

Projects	Emission Reductions (tpd)
Completed and ongoing (2007-2011)	0.6
Scheduled	0.05
Under investigation	0.07 - 0.08
Total	**0.7**

Chapter 4 – Costs and Cost Effectiveness

This chapter discusses both the preliminary analysis in December 2014 and the revised analysis in 2015.

Staff's Preliminary Estimates

Staff preliminary analyses as of December 2014 for costs and cost effectiveness are discussed in Part I, Appendices A – E, for the refinery sector and Part II, Appendices M – S, for the non-refinery sector, respectively. A summary of the methods used for costs and cost effectiveness analyses and the results of these detailed analyses are provided in this Chapter.

The Present Worth Value~~s~~ (PWV) of a control device are the total costs to install and operate the control device estimated at the present currency value. The PWV consists of the Total Installed Costs (TIC) and Annual Operating Costs (AC) during the entire economic life of the control equipment using the Discounted Cash Flow (DCF) Method as follows:

$$PWV = TIC + (15.62 \times AC)$$

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
15.62 = a factor to estimate the cumulative annual operating costs during a 25-year life of a control device

The incremental cost effectiveness value of a control device is estimated as follows:

$$CE_{\text{incremental}} = (PWV_{2015\ BARCT} - PWV_{2000/05\ BARCT}) / (ER_{2015\ BARCT} - ER_{2000/05\ BARCT})/25/365$$

Where:

$CE_{\text{incremental}}$ = Incremental Cost Effectiveness, \$/ton
$PWV_{2015\ BARCT} - PWV_{2000/05\ BARCT}$ = Incremental costs to achieve additional control to meet the 2015 BARCT level from the 2000/2005 BARCT level
$ER_{2015\ BARCT} - ER_{2000/05\ BARCT}$ = Incremental emission reductions to achieve the 2015 BARCT level from the 2000/2005 BARCT level

The incremental costs and cost effectiveness were calculated based on the 2011-2012 baseline emissions and the DCF method. Staff also presented the cost effectiveness estimated with the

Levelized Cash Flow (LCF) method. In the cost effectiveness analysis using the DCF method, staff used a cutoff level of $50,000 per ton. The $50,000 per ton cutoff is based on the policy developed during the 2008 – 2010 SOx RECLAIM rule amendment that was adopted by the District Governing Board. The results of staff's preliminary estimates in 2014 for PWVs and cost effectiveness values are summarized in Tables 4.1 and 4.2; and the revised estimates are summarized in Tables 4.3 and 4.4.

Consultants' Estimates

In the Fall of 2014, the SCAQMD staff contracted with two consultants, NEC and ETS, to conduct independent studies on costs and cost effectiveness. The consultants' reports are included as separate documents (Addenda 1 and 2). Table 4.1 below shows a comparison between staff's and NEC's estimates for the refinery sector, and Table 4.2 shows a comparison between staff's and ETS's estimates for the non-refinery sector.

Refinery Sector

For the refinery sector, as shown in Table 4.1, NEC and staff recommended BARCT levels of 2 ppmv for gas turbines, FCCUs, boilers/heaters, and SRU/TG incinerators. For the refinery coke calciner, NEC recommended a BARCT level of 5 - 10 ppmv instead of 2 ppmv previously recommended by staff. Staff agreed with NEC's recommendation and changed the recommendation to 10 ppmv BARCT for the coke calciner. Different approaches were used to estimate the SCR costs for FCCUs, boilers/heaters and SRU/TG incinerators, an adjustment was made to the proposed shave amount to account for the different engineering and cost assumptions. Please refer to Part I, Appendix F - J, for further discussion. Table 4.3 shows the ranges of PWVs and cost effectiveness values for the refinery sector based on the revised proposal.

Table 4. 1 – Initial Proposal - BARCT Levels, Costs and Cost Effectiveness - Refinery Sector (December 2014)

Equipment Category	Proposed 2014 BARCT	Staff's Estimates		Estimates Using NEC's Information		Incremental DCF Cost-Effectiveness
		Incremental Reductions (tpd)	**PWVs ($M)**	**Incremental Reductions (tpd)**	**PWVs ($M)**	**$/ton NOx Reduced**
Gas Turbines	2 ppmv	4.14	97.7	4.14	52.7	1K - 3K
FCCUs	2 ppmv	0.43	152	0.43	211	3K - 18K
Coke Calciner	5 ppmv	0.21(1)	22 - 61	0.17(2)	39.5	11K - 25K
Boilers/Heaters >40 mmbtu/hr	2 ppmv	1.05	254.5	0.61	162	27K - 29K
SRU/TG Incinerators	2 ppmv	0.35	49 - 68	0.32	120	15K - 48K
Total		**6.18**	**575 - 633**	**5.67**	**585**	**7K - 12K (3)**

Note: 1) Based on 5 ppmv BARCT, 2) Based on 10 ppmv BARCT, 3) Weighted average by NOx reductions

Non-Refinery Sector

For the non-refinery sector, ETS agreed with the proposed BARCT levels- recommended for all categories. ETS's estimated costs and incremental costs were slightly higher than staff's estimates as shown in Table 4.2. Table 4.4 shows the revised ranges of PWVs and cost effectiveness values for the non-refinery sector.

Table 4. 2 – Initial Proposal - BARCT Levels, Costs and Cost Effectiveness - Non-Refinery Sector (December 2014)

	Proposed 2014 BARCT	**Incremental Reductions (tpd)**	**Staff's PWVs ($M)**	**ETS's PWVs ($M)**	**Incremental DCF CE $/ton NOx Reduced**
Cement Kilns	0.5 lb/ton clinker	1.32	34 - 107	36 - 112	3 - 10K
Container Glass	0.24 lb/ton pulled	0.24	4 - 14	6 - 15	3 - 7K
Sodium Silicate Furnace	1.28 lb/ton pulled	0.09	2.8 - 4.6	3 - 4.6	4 - 6K
Metal Heat Treating Furnaces >150 mmbtu/hr	9 ppmv @ 3% O2	0.56	8 - 10	8 - 10	3 - 3.8 K
Gas Turbines	2 ppmv @15% O2	1.04	3 - 14	3 - 14	5 - 36K
ICEs	11 ppmv @15% O2	0.84	0.9 - 4	0.9 - 4	5 - 8K
Boilers >40 mmbtu/hr	No new BARCT	0	0	0	
Total		**6.18**	**53 - 154**	**57 - 160**	**4 - 15 K (1, 2)**

Note: 1) LCF ranges from $5 K - $57 K per ton, 2) Weighted average by NOx reductions

Staff Recommendations

After the facility visits and the consultants' analyses were completed, staff revisited the cost estimations and made modifications to the preliminary proposals. Staff's revised recommendations are presented below.

Refinery Sector

Staff's current recommendations for the refinery sector are tabulated in Table 4.3. Please refer to Part I, Appendices A-J for additional information.

Table 4. 3 - Staff's Revised Recommendation for Refinery Sector (May 2015)

	2015 BARCT	Incremental Reductions (tpd)	PWVs ($M)	Incremental Cost Effectiveness ($K/ton DCF)	Note
FCCUs	2 ppmv	0.43	152 – 391	3 – 13	1
Gas Turbines	2 ppmv	4.14	53 – 98	1 – 3	2
Boilers/Heaters >40 mmbtu/hr	2 ppmv	0.94	237	28	3
Coke Calciner	10 ppmv	0.17	40 - 91	19 – 25	4
SRU/TG Incinerators	2 ppmv	0.32	83 - 106	28 – 40	5
Total		**6.00**	**565 – 923**	**10 – 17**	6

Notes:

1) See Appendix A. The PWV of $152M are for the case where all 5 refineries would install SCRs. The PWV of $391 M are for the case where SCRs would be installed at Ref 5 and 6 and LoTOx and scrubbers at Ref 4, 7 and 9 to reduce both NOx and SOx.
2) See Appendix C. The PWV of $53 M was estimated by NEC for adding catalysts to all SCRs. The PWV of $98 M was derived by SCAQMD staff for adding catalysts to Ref 1's SCRs and new SCRs to Ref 4 - 7.
3) See Appendix B.
4) See Appendix D. The PWV of $40M was estimated by NEC for LoTOx technology and $91 M was staff's estimates for Tri-Mer technology
5) See Appendix E. The PWV of $83 M was for SCRs and $106 M for LoTOx applications
6) Incremental cost effectiveness is the weighted average by NOx reductions. Low end of incremental cost effectiveness = $565 M/ (6*25*365) = $10,320 per ton NOx reduced. High end of incremental cost effectiveness = $923 M/ (6*25*365) = $16,858 per ton NOx reduced.

Non-Refinery Sector

Table 4.4 tabulates staff's current recommendations for the non-refinery sector. Please refer to Part II, Appendices M-R for further information.

Table 4. 4 - Staff's Recommendation for Non-Refinery Sector (May 2015)

	2015 BARCT	Incremental Reductions (tpd)	PWVs ($M)	Incremental Cost Effectiveness ($K/ton DCF)	Note
Cement Kilns	0.5 lb/ton clinker	1.29	61 - 152	5 - 11	1
Container Glass Melting Furnaces	0.24 lb/ton glass pulled	0.24	6 - 15	3 - 7	2
Sodium Silicate Furnace	1.28 lb/ton glass pulled	0.09	3.0 - 4.6	4 - 8	3
Metal Heat Treating Furnace > 150 mmbtu/hr	9 ppmv at 3% O2	0.56	8 - 10	3 - 3.8	4
Gas Turbines	2 ppmv at 3% O2	1.04	~109	5 - 36	5
ICEs	11 ppmv at 15% O2	0.84	~37	5 - 8	6
	Total	**4.06**	**224 - 328**	**6 - 9**	7, 8, 9, 10

Note:

1) Refer to Appendix M
2) Refer to Appendix N
3) Refer to Appendix O
4) Refer to Appendix P
5) Refer to Appendix Q
6) Refer to Appendix R
7) Incremental costs effectiveness is the weighted average by NOx reductions. With cement kilns: low end of incremental cost effectiveness = $224 M/ (4.06*25*365) = $6 K per ton NOx reduced, and high end of incremental cost effectiveness = $328 M/ (4.06*25*365) = $9 K per ton NOx reduced.
8) The incremental emission reductions would be 4.06 tpd including the incremental reductions for the cement kilns. Without the cement kilns, the incremental emission reductions would be 2.77 tpd.
9) The range for PWVs would be $224 M – $328 M including the PWVs for the NOx control device for cement kilns. The range of PWVs would be $163 M - $176 M without the control devices for cement kilns.
10) Incremental costs effectiveness is the weighted average by NOx reductions. Without cement kilns: low end of incremental cost effectiveness = $163 M/ (2.77*25*365) = $6 K per ton NOx reduced, and high end of incremental cost effectiveness = $176 M/ (2.77*25*365) = $7 K per ton NOx reduced.

Chapter 5 - RTC Reductions

Remaining Emissions

As discussed in the Public Process section, staff started the discussion with stakeholders on the calculation method that would be used to estimate the RTC reductions in 2013. One of the parameters used in the calculation for the RTC reductions is the remaining emissions projected to 2023. The 2023 remaining emissions estimates by staff were first presented to the stakeholders at the January 22, 2014 Working Group Meeting. Staff later refined the numbers and presented them to the stakeholders in the July 31, 2014 and April 29, 2015 Working Group Meetings. The changes made are summarized below.

Refinery Sector

Table 5.1 tabulates the estimated 2023 remaining emissions for each NOx source category in the refinery sector. In 2014, staff estimated the total 2023 remaining emissions to be 2.56 tpd. In 2015, staff revised the number to 2.76 tpd as a result of the following changes:

- The BARCT level for coke calciner was changed from 2 ppmv to 10 ppmv. As a result, the remaining emissions for coke calciner increased to 0.08 tpd.

- The costs of control for boilers/heaters and SRU/TG incinerators were revised to be higher. As a result, the cost effectiveness for several boilers/heaters and one incinerator became higher than the policy threshold of $50,000 per ton, and these units were excluded from the equipment that contributed to the emission reductions. The remaining emissions for the boilers/heaters >40 mmbtu/hr increased to 0.85 tpd, and the remaining emissions for the SRU/TG incinerators increased to 0.11 tpd.

Table 5. 1 - Remaining Emissions for Refinery Sector

	Total No of Units	2011 Emissions (tpd)	2000/2005 BARCT	2011 Emissions at 2000/2005 BARCT (tpd)	2015 BARCT	2011 Emissions at 2015 BARCT (tpd)	2023 Emission Reductions Beyond 2000/2005 BARCT (tpd)	2023 Emission at 2015 BARCT with GF = 1 (tpd)
FCCUs/CO Boilers	8	1.08	85% control	0.60	2 ppmv	0.17	0.43	0.17
Turbines/Duct Burners	21	1.33	62.27 lbs/mmcft	4.86	2 ppmv	0.72	4.14	0.72
Coke Calciner	2	0.55	30 ppmv	0.25	10 ppmv	0.08	0.17	0.08
SRU/TG Incinerators	17	0.43	RV	0.43	2 ppmv (or 95% control)	0.11	0.32	0.11
Boilers/Heaters > 110 mmbtu/hr	73	4.88	5 ppmv	0.82	2 ppmv	0.38	0.44	0.38
Boilers/Heaters >40-110 mmbtu/hr	69	2.00	25 ppmv	0.97	2 ppmv	0.47	0.50	0.47
Boliers/Heaters 20-40 mmbtu/hr	52	0.45	9 ppmv	0.10	n/a	0.10	0.00	0.10
Boilers/Heaters <20 mmbtu/hr	18	0.06	12 ppmv	0.02	n/a	0.02	0.00	0.02
Other Major/Large Sources	5	0.11	n/a	0.10	n/a	0.10	0.00	0.10
Other Process Units	n/a	0.60	n/a	0.60	n/a	0.60	0.00	0.60
Total	**265**	**11.50**		**8.76**		**2.76**	**6.00**	**2.76**

Non-Refinery Sector

Table 5.2 tabulates the estimated 2023 remaining emissions for each NOx source category in the non-refinery sector. In 2014, staff estimated the 2023 remaining emissions for the non-refinery sector to be 8.77 tpd. In 2015, staff revised the number to 7.47 tpd as a result of the following changes:

- The baseline for ~~electrical~~ electricity generating facilities was changed from 2011 to 2012. The 2011 and 2012 baseline emissions were 1.45 tpd and 2.50 tpd, respectively. Staff also used either the BACT level or the level stated in the permit conditions to estimate the emission reductions beyond the levels that could be achieved by the 2005 BARCT. In addition, staff used the most recent growth factor of 0.868 to estimate the remaining emissions for the ~~electrical~~ electricity generating facilities. As a result of these changes, the 2023 remaining emissions for ~~electrical~~ electricity generating facilities were changed to 2.04 tpd.

- The remaining emissions from non-~~electrical~~ electricity generating facilities were changed to 1.37 tpd; and

- The remaining emissions from other sources were changed to 4.06 tpd.

Table 5. 2 - Remaining Emissions for Non Refinery Sector (May 2015)

POWER PLANTS*	# of Facilities	2012 Emissions (tpd)	2000/2005 BARCT	2012 Emissions at BARCT/BACT (tpd)	2015 BARCT	2012 Emissions at 2015 BARCT (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	Growth Factor	2023 Emissions at 2015 BARCT (tpd)
TOTAL	**30**	**2.50**	**P/O or BACT level**	**2.35**	**No new BARCT**	**2.35**	**0**	**0.8683**	**2.04**
NON-POWER PLANTS	**# of Units**	**2011 Emissions (tpd)**	**2000/2005 BARCT**	**2011 Emissions at 2000/2005 BARCT (tpd)**	**2015 BARCT**	**2011 Emissions at 2015 BARCT (tpd)**	**Emission Reductions Beyond 2005 BARCT (tpd)**	**Growth Factor**	**2023 Emissions at 2015 BARCT (tpd)**
Boilers	16	0.08	9-12 ppm	0.07	No new BARCT	0.07	0	0.96	0.07
Heaters	3	0.01	60 ppm	0.01	No new BARCT	0.01	0	0.93	0.01
Furnaces >150 MMBTU/hr	2	0.49	45 ppm	0.70	9 ppm	0.14	0.56	0.93	0.13
Furnaces	10	0.31	45 ppm	0.31	No new BARCT	0.31	0	0.93	0.29
Glass Melting Furnaces	2	0.30	1.2 lb/ton	0.30	80% Reduction	0.06	0.24	1.18	0.07
Sodium Silicate Furnace	1	0.11	6.4 lb/ton	0.11	80% Reduction	0.02	0.09	1.21	0.02
Gas Turbines (non-OCS)	14	1.43	61.45 lb/mmcf	1.24	2 ppm	0.21	1.04	1.10	0.23
Gas Turbines (OCS)	6	0.49	61.45 lb/mmcf	0.12	No new BARCT	0.12	0	1.46	0.18
ICEs (non-OCS)	25	0.35	217.36 lb/mmcf	1.05	11 ppm	0.21	0.84	1.03	0.22
ICEs (OCS)	6	0.03	217.36 lb/mmcf	0.11	No new BARCT	0.11	0	1.46	0.16
*Cement Kilns***	*2*	*1.61*	*2.73 lb/ton*	*1.61*	*0.5 lb/ton*	*0.32*	*1.29*	*0.9*	*0.29*
TOTAL	**87**	**3.60**		**4.02**		**1.26**	**2.77**		**1.37**
Other Sources* **		**3.12**		**3.12**		**3.12**			**4.06**
TOTAL NON-REFINERY		**9.22**		**9.49**		**6.73**	**2.77**		**7.47**

***This includes all power plants in RECLAIM. Calendar year 2012 AER reported fuel usage was used to calculate emissions at BARCT/BACT level.**

****CPCC's emissions and emission reductions have NOT been included in the totals, this facility did not have any emissions in CY2011. CY2008 emissions were used to calculate the emission reductions.**

*****Includes Non-Refinery, Non-Power Plant Process Units in the Top 37 and all other sources outside the Top 37.**

Calculation Method for RTC Reductions

The RTC reductions are calculated as follows:

RTC Reductions = RTC Holdings – (Remaining Emissions x Compliance Margin)

Where

RTC Holdings = 26.5 tpd
Remaining Emissions = ($R_{Refinery}$ + $R_{Non\text{-}Refinery}$ + $R_{Adjustment}$)
$R_{Refinery}$ = Remaining emissions for refinery sector x Growth Factor
$R_{Non\ Refinery}$ = Remaining emissions for non-refinery sector x Growth Factors
$R_{Adjustment}$ = Potential adjustments set aside for new ~~electrical~~ electricity generating facilities
Compliance margin = 10% as provided in the previous RECLAIM amendments

An example shown below was presented at the April 29, 2015 Working Group Meeting:

$R_{Refinery}$ = 2.76 tpd including growth factor of 1 as shown in Table 5-1
$R_{Non\ Refinery}$ = 7.47 tpd including growth factor of 1.1 as shown in Table 5-2
$R_{Adjustment}$ = 0.07 tpd potential adjustments for new ~~electrical~~ electricity generating facilities due to SONGS shutdown and 0.29 and 0.10 for CPCC and other shutdown facilities
RTC Reductions = 26.5 – ([(2.76 + 7.47 + 0.07) x 1.1] + (0.29 + 0.10))
= 26.5 – 11.7 = 14.8 tpd

Regional NSR Holding Account for Electric*ity*~~*al*~~ Generating Facilities

Staff has received input from several electric*ity*~~*al*~~ generating facility operators that have concerns with concurrent compliance with the RTC allocation shave and the new source review (NSR) holding requirements per Rule 2005. New facilities that entered into RECLAIM after October 15, 1993 must hold RTCs for all of their equipment at the permitted potential to emit (PTE) level at the beginning of every compliance year. Pre-RECLAIM power producing facilities only need to hold RTCs for one year if their PTEs increase, unless their new PTEs exceed their initial 1993 allocation. Electric*ity*~~al~~ ~~producing~~ generating facilities often operate at a capacity factor well below the PTE level during any given compliance year. The combustion equipment for these facilities is also already at the BARCT or BACT emission level. These facilities would be shaved and be subject to complying with the NSR holding requirements as well as their annual emission reconciliation requirements.

Staff has proposed the creation of a Regional NSR Holding Account to help address the NSR holding requirements programmatically for all post-1993 electric*ity*~~al~~ ~~producing~~ *generating* facilities. This account would reduce the individual facility NSR hold requirements by the amount that they were shaved and would be comprised of the shaved RTCs from these facilities as discrete credits. All electric*ity*~~al~~ generating facilities would be allowed to access this account to offset emissions (rather than just satisfy NSR holding requirements) if the Governor of California declares a state of emergency regarding reliable energy supply or grid stability in the Basin. The size of the Regional NSR Holding Account would be equivalent to the RTCs shaved from the affected post-1993 ~~electrical~~ electricity generating facilities. This approach serves two purposes. First, it provides relief from the different and burdensome NSR holding requirements for these newer facilities relative to older electric*ity*~~al~~ ~~generation~~ generating facilities. Second, it provides an emergency source of RTCs to be accessed in the case of a power crisis. Any new electric*ity*~~al~~ generating facility that enters RECLAIM after the proposed amendment would still be subject to the full multi-year NSR holding requirements.

Staff Proposal and CEQA Alternatives

Table 5.3 summarizes the staff proposal which includes a NOx RTC shave of 14 tpd rather than the 14.8 tpd calculated above. The 0.8 tpd difference is to account for comments received from stakeholders regarding uncertainties in the BARCT analysis, and to provide some additional compliance margin. Staff is currently proposing that the 14 tpd RTC reductions be distributed to 56 facilities and investors that collectively hold about 90% of the 26.5 tpd RTCs. The 56 affected facilities include 9 major refineries, 21 ~~electrical~~ electricity generating facilities, and 26 other top emitting facilities as shown in Table 5.5. Staff is proposing not to shave the remaining 219 facilities that hold only 10% of the 26.5 tpd RTCs because there was limited or no new BARCT identified for other types of equipment and operations there. Other approaches to determine the RTC reductions as shown in Table 5.4 were analyzed as project alternatives in the CEQA analysis. For further information, please refer to Part III, Appendix U of this staff report.

Staff is proposing the following implementation schedule:

2016: 4 tons per day
2018: 2 tons per day
2019: 2 tons per day
2020: 2 tons per day
2021: 2 tons per day
2022: 2 tons per day

As shown in Table 1-1 of Chapter 1, in the past five years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5.5 to 8 tpd, and thus staff is proposing a reasonable initial 4 tpd RTC reduction in 2016. Additional BARCT implementation will take about 2 – 4 years for planning, permitting, and construction, and staff is proposing that the remaining shave of 10 tpd take place between 2018 and 2022.

Table 5. 3 - Staff Proposal - Affected Facilities and Percent Shave

	Major Refineries and Investors	Non-~~Electrical~~ Electricity generating facilities	~~Electrical~~ Electricity generating facilities	Bottom 10% of RTC Holders	Total
No of facilities	9	26	21	219	275
Current RTCs	14.6	9.1		2.8	26.5
RTC Reductions	9.6	4.4		0	**14.0**
Remaining RTCs	5	4.7		2.8	12.5
Percent Shave	9.6/14.6 = 66%	4.4/9.1 = 49%		0%	

Note that investors are counted as one facility and grouped with the refineries.

Table 5. 4 - Alternatives for CEQA Analysis

	Alternative	Major Refineries + Investors	Non-Major Refineries/ Facilities	~~Electrical~~ Electricity Generating Facilities	Bottom 10% of RTC Holders
1	Shave 14 tpd uniformly across all 275 facilities	53%	53%	53%	53%
2	Shave 15.87 tpd (w/o 10% compliance margin) uniformly across all 275 facilities	60%	60%	60%	60%
3	Shave 8.8 tpd (the difference in emission reductions between previous BARCT and 2015 BARCT) uniformly across all 275 facilities	33%	33%	33%	33%
4	No project	0%	0%	0%	0%
5	Shave 14 tpd weighted by BARCT reduction contribution and distributed to all 275 facilities	66%	37%	37%	37%

Table 5. 5 - List of Facilities and Investors that would have RTCs Reduced

Facility ID	Name
800030	CHEVRON PRODUCTS CO.
800089	EXXONMOBIL OIL CORPORATION
174655	TESORO REFINING & MARKETING CO, LLC
800436	TESORO REFINING AND MARKETING CO, LLC
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL
800026	ULTRAMAR INC
115394	AES ALAMITOS, LLC
115663	EL SEGUNDO POWER, LLC
800074	LA CITY, DWP HAYNES GENERATING STATION
800128	SO CAL GAS CO
800075	LA CITY, DWP SCATTERGOOD GENERATING STN
46268	CALIFORNIA STEEL INDUSTRIES INC
115536	AES REDONDO BEACH, LLC
160437	SOUTHERN CALIFORNIA EDISON
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY
174591	TESORO REF & MKTG CO LLC,CALCINER
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST
152707	CPV SENTINEL LLC
169754	OXY USA INC
115389	AES HUNTINGTON BEACH, LLC
7427	OWENS-BROCKWAY GLASS CONTAINER INC
18931	TAMCO
4477	SO CAL EDISON CO
800183	PARAMOUNT PETR CORP
43201	SNOW SUMMIT INC
172005	NEW- INDY ONTARIO, LLC
146536	WALNUT CREEK ENERGY, LLC
800189	DISNEYLAND RESORT
156741	HARBOR COGENERATION CO, LLC
151798	TESORO REFINING AND MARKETING CO, LLC
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA
11435	PQ CORPORATION
4242	SAN DIEGO GAS & ELECTRIC
115314	LONG BEACH GENERATION, LLC
17953	PACIFIC CLAY PRODUCTS INC
153992	CANYON POWER PLANT
800127	SO CAL GAS CO
800193	LA CITY, DWP VALLEY GENERATING STATION
119907	BERRY PETROLEUM COMPANY
25638	BURBANK CITY, BURBANK WATER & POWER
124838	EXIDE TECHNOLOGIES
51620	WHEELABRATOR NORWALK ENERGY CO INC
5973	SO CAL GAS CO
800168	PASADENA CITY, DWP
3968	TABC, INC
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI
155474	BICENT (CALIFORNIA) MALBURG LLC

Facility ID	Name
800181	CALIFORNIA PORTLAND CEMENT CO
166073	BETA OFFSHORE
114801	SOLVAY USA, INC.
800153	US GOVT, NAVY DEPT LB SHIPYARD
8547	QUEMETCO INC
1073	BORAL ROOFING LLC
700126	GENERAL ELECTRIC COMPANY
129816	INLAND EMPIRE ENERGY CENTER, LLC
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC
	INVESTORS

Chapter 6 – Summary of the Proposed Changes in Rule Language and Draft Program Environmental Assessment

Appendix X contains more detailed information regarding the changes described below.

Rule 2001 (g)(1) to (4) and (i)(1)(K) and (i)(2)(O) – Electricity Generating Facilities Opt-out of NOx RECLAIM

Rule 2001 includes a provision that would allow the owner or operator of an electricity generating facility (EGF) to opt out of the NOx RECLAIM program. An opt-out plan would need to demonstrate that at least 99 percent of the EGF's NOx emissions for the most recent 3 compliance years are at current BARCT or BACT. The rule specifies how New Source Review requirements would be met, how RTCs will be handled, and that Facility Permit amendments would be required to ensure that BARCT or BACT levels would be maintained. The EGF operator would need to comply with any source specific rule limits as quickly as possible, but no later than 3 years after approval of their opt-out plan. The owner or operator at multiple EGFs under common control would have one opportunity to apportion the NOx limits among its facilities. Monitoring, reporting, and recordkeeping requirements of Rule 2012 and its associated protocols would continue to apply unless the Executive Office approves an alternative plan that is sufficient to determine compliance with all applicable rules.

As mentioned above, an EGF may opt out of RECLAIM provided it meets certain criteria. Specifically, the facility will be subject to a condition limiting the facility's NOx emissions, for a facility existing as of October 1993, to the amount of RTCs held by the facility as of September 22, 2015, and for a facility built after October 1993, to the amount of RTCs required to be held pursuant to Rule 2005. However, if the operator has more than one facility subject to RECLAIM upon removing all of the facilities from RECLAIM simultaneously, the operator has a single opportunity to re-distribute the RTCs holdings among the various facilities in such a way that the RTCs held for each facility will not exceed the maximum emissions that can be generated by the equipment permitted at that facility based on the existing permit conditions.

Once the facility is re-issued its permit without RECLAIM requirements, subsequent modifications to the facility will be subject to provisions of Regulation XIII – New Source Review for NOx, as well as other pollutants. There are four possible scenarios that may trigger New Source Review (NSR) provisions for NOx. The table below shows the potential conditions that may be imposed for each scenario:

Scenario	Offset Exemption	Emission Limiting Conditions
Replacement of existing equipment with other equipment that is functionally equivalent and no increase in maximum emissions	1304 (a)(1)	Facility annual emission limit remains; no need for additional individual equipment limit for the remaining existing equipment
Replacement of an electric utility steam boiler with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules	1304 (a)(2)	Facility annual emission limit remains; no need for individual equipment limit for the remaining existing equipment
Concurrent modification or replacement of existing equipment or removal and addition of different equipment that result in a net decrease in emission potential	1304 (c)(2)	Facility annual emission limit remains; no need for individual equipment limit for the remaining existing equipment
Modification or replacement of existing equipment that result in a net increase of emissions, or construction of new equipment	None	May apply for individual equipment limits prior to applying for modification or new construction; Facility annual emission limit will be updated to account for offset provided for new or modified source

Rule 2002 (f)(1) – BARCT Proposed Levels and RTC Reductions

The staff proposal of the new BARCT levels for the refinery and non-refinery sectors are summarized in Table 6 of Rule 2002.

The proposal would result in a programmatic reduction of 14 tons per day RTC holdings over 7 years. Four tons per day would be reduced in 2016 and the remainder would be reduced in equal increments from 2018 to 2022. There would be no reductions proposed for the year 2017. These reductions are reflected in subparagraphs (f)(1)(B) and (f)(1)(C). Subparagraph (f)(1)(B) includes all of the Major Refineries and Investors. The Major Refineries are listed in Table 7 of Rule 2002. Subparagraph (f)(1)(C) includes all other facilities subject to the reduction in NOx RTCs. These facilities are listed in Table 8 of Rule 2002.

The remaining NOx RTCs after a shave for any compliance year would be the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(B) multiplied by the RTC holdings (as of September22, 2015) of all the Major Refineries listed in Table 7 plus the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(C) multiplied by the RTC holdings (as of September 22, 2015) of all the facilities listed in Table 8. Please see Appendix U for further explanation on how the factors in subparagraphs (f)(1)(B) and (C) were derived. Appendix U also contains the list of facilities including NOx RTC holders not designated as Facility Permit Holders as of September 22, 2015, except any NOx RTC holders listed in Table 8.

Since the RTC reductions specified in subparagraph (f)(1)(A) have been realized, the conversion of non-tradable/non-usable NOx RTCs to tradable/usable NOx RTCs is no longer applicable to the RTC reductions specified in this subparagraph. The tradable/usable NOx RTCs specified in subparagraph (f)(1)(A) would remain intact and used for calculating RTC reductions for facilities entering the RECLAIM program. However the same approach in converting adjustment factors previously specified in subparagraph (f)(1)(A) would now be applied to the RTC reductions specified in subparagraphs (f)(1)(B) and (f)(1)(C).

Subparagraphs (f)(1)(B) and (f)(1)(C) also include adjustment factors to obtain Non-tradable/Non-usable holdings. The quantity of Non-tradable/Non-usable NOx RTCs is equal to the incremental shave amount in the given compliance year. Subparagraph (f)(1)(G) and (f)(1)(H) specify that shaved RTCs from newer ~~electrical~~ electricity generating facilities listed in Table 9 will be used to fund a Regional NSR Holding Account that can be used, along with their Non-tradable/Non-usable holdings, by these facilities to help meet their ongoing NSR holding requirements.

Subparagraph (f)(1)(E) updates the 12-month rolling average trigger to $22,500 per ton for discrete credits. A trigger level of $35,000 per ton has been added for a 3-month rolling average in subparagraph (f)(1)(I). If RTC prices exceed either of these levels, a report to the Board and a program review are required. Subparagraph (f)(1)(J) includes a 12-month rolling average for Infinite Year Block (IYB) RTCs of $200,000 per ton. If credit prices are lower than this amount beginning in 2019, then a report to the Board is also required.

Subparagraph (f)(1)(I) describes provisions for conversion of Non-tradable/Non-usable holdings to Tradable/Usable NOx RTCs if the 12-month rolling average RTC price exceeds $22,500 per ton. This trigger corresponds to the adopted 2012 AQMP cost effectiveness threshold that triggers additional analysis of proposed rules. Similarly, (f)(1)(I) also requires that the Executive Officer's report to the Board on the trigger price also include a commitment and schedule to conduct a more rigorous cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program.

Subparagraph (f)(1)(~~L~~M) clarifies the method for determining allocations for existing facilities that enter RECLAIM after the date of adoption of the proposed amendments.

Rule 2002 (f)(4) and (f)(5) – Regional NSR Holding Account and State of Emergency Related to ~~Electrical~~ Electricity Generating Facilities

A new electricricity~~al~~ generating facility (EGF), along with all new RECLAIM facilities, must hold sufficient RTCs to offset their entire potential to emit (PTE) for one year prior to commencement of operation and at the beginning of every compliance year thereafter. These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. ~~Electrical generating facilities~~EGFs often~~m~~ have PTEs that far exceed their actual emissions, and cannot readily reduce their PTEs given that they must be available for grid support if called upon. Given this burdensome requirement, staff is proposing to create ~~an~~a Regional NSR Holding Account, held by the SCAQMD, that would be used for the purpose of helping such facilities comply with the NSR requirements specified in Rule 2005. These proposed requirements are specified in Rule 2002 paragraph (f)(4). The RTCs in the Regional NSR Holding Account would not be available to offset actual emissions, except for the situation described below.

Staff is proposing in paragraph (f)(5) that during a State of Emergency declared by the Governor related to electricity demand or power grid stability in the Basin, any ~~electrical generating facility~~EGF can use their Non-tradable/Non-usable NOx RTC holdings to offset their emissions after exhausting their Tradable/Usable holdings. Furthermore, if their Non-tradable/Non-usable NOx RTC holdings are exhausted, they may apply for the use of NOx RTCs in the Regional NSR Holding Account on a quarterly basis. Subparagraphs (f)(4)(i) – (iii) describe the criteria that the Executive Officer must consider in determining the amount and the distribution of these RTCs. If the total RTCs requested exceeds the supply in the Account, the RTCs will be distributed proportionately according to the verified offset needs of the requesting facilities

The RTCs in the Regional NSR Holding Account would be 0.827 tons per day for 2023 & beyond (See Appendix U). These RTCs would be derived from the RTC reductions applied to the newer ~~electrical~~ electricity generating facilities listed in Table 9.

Rule 2002 (i) – RTC Reduction Exemption

Given that no facilities in the history of the RECLAIM program have applied for an exemption pursuant to subdivision (i), and given the unlikelihood that a facility could meet the stringent requirements listed therein, staff is proposing to remove the subdivision in its entirety.

Rule 2002 (i) – Facility and Equipment Shutdowns

The proposed rule includes provision to address the retirement of RTCs from complete facility closure or equipment shutdowns that represent twenty-five percent or more of a facility's emissions for any quarter within the previous 2 compliance years. This would apply to any facility listed in Table 7 or 8 of Rule 2002. Permits associated with the equipment being shut down would be surrendered, and the RTCs for future years would be retired from the RECLAIM program.

Rule 2005 – Requirements for New ~~Electrical~~ Electricity Generating Facilities

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state NSR program requirements. One of the requirements is to ensure that the facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. For an RECLAIM facility existing prior to the adoption of the RECLAIM program, the amendments made in June 3, 2011 required the RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but will not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits. However, a new RECLAIM facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any unused RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter. To remedy this burdensome RTC holding requirement for new ~~electrical generating facilities~~EGFs that cannot change their allowable NOx emissions in their Facility Permit, staff is proposing a Regional NSR Holding Account described in Rules 2002(f)(4) above. Proposed changes in Rule 2005 would assure that the RTCs in the Account would only be used the for the purpose of complying with the NSR requirements (other than access during a power crisis as also described in 2002(f)(4)) . Please see Appendix X for further explanations.

Other Administrative Amendments

Besides the changes described in Rule 2002 and 2005 described above, staff also proposes administrative amendments to Regulation XX to clarify the rule language and to ensure effective and consistent implementation of the RECLAIM program.

Rule 2002(b)(5) - 5-Year Limitation on Amending Annual Emission Reports

Some facilities entering the RECLAIM program have sought to amend their past AERs, which dated as far back as 1989, in ways that increase the initial SOx and/or NOx allocations previously determined pursuant to Rule 2002. The longer the time that has elapsed between the reporting period and the submittal of the amendment, the more problematic the process of validating the proposed changes and the supporting documentation. In fact, such validation has been infeasible in some cases. Therefore, staff is proposing to add language to Rule 2002(b)(5) to provide clarity on which annual report submittals and/or revisions may be considered by staff in determining facility allocations.

Rule 2002 (Table 4) – Minor Typographical Edit

Rule 2002's Table 4 – RECLAIM SOx Tier III Emission Standards includes a row for Diesel Combustion, which includes a BARCT Emission Standard of "15 ppmv as required under Rule 431.2." However, the standard in Rule 431.2 is actually "15 ppm by weight" rather than 15 ppmv (*i.e.*, 15 ppm by volume). The staff proposal would correct the Table 4 entry to "15 ppm by weight as required under Rule 431.2," consistent with the definition of Low Sulfur Diesel at Rule 431.2(b)(5).

Rules 2011 and 2012 - Delayed RATA Tests due to Extenuating Circumstances

Rules 2011 and 2012 set forth monitoring, reporting, and recordkeeping requirements for sources of SOx and NOx at RECLAIM facilities. The accompanying Appendices A to these rules outline in greater detail the technical specifications required for monitoring, reporting, and recordkeeping for RECLAIM sources such as the timing and frequency of Semi-Annual Assessments in the form of Relative Accuracy Test Audits (RATAs) for CEMS. RATAs must be conducted while the equipment is in operation. Equipment monitored by CEMS at some RECLAIM facilities, however, may experience extenuating circumstances that prevent them from conducting RATA tests in a timely manner.

Additionally, facilities under contract with the California Independent System Operator (CalISO), as well as ~~electrical~~ electricity generating facilities owned and operated by municipalities, have experienced difficulties in meeting RATA deadlines because their equipment operates based on current energy demand and may not operate long enough (or at all) to conduct a RATA in the quarter in which RATA is due. ~~Electrical~~ Electrcity generating facilities with equipment under contract with CalISO or owned and operated by municipalities often do not know when demand for electricity will result in generation equipment being required to operate until a day prior, creating scheduling difficulties in conducting RATAs and precluding the use of non-operational status. The inherent inconsistent operational nature of such equipment at electric generating facilities sometimes causes a need to postpone their RATAs.

Under current rule requirements, facilities having such extenuating circumstances seek variances for indeterminate amounts of time. The proposed amendments would, under specific conditions and criteria, allow RECLAIM Facility Permit Holders of equipment experiencing these extenuating circumstances to postpone RATAs. The specific conditions and criteria are further explained in details in Appendix X.

Proposed Amended Rules 2011, Appendix A, Attachment E and 2012, Appendix A, Attachment F – *Clarification of "Standard Gas Conditions"*

Proposed amendments to Rule 2011, Appendix A, Attachment E and 2012 Appendix A, Attachment F would clarify standard gas conditions by giving each facility operator the option to use either the 60 ºF standard or the 68 ºF standard provided one or the other is used consistently throughout the facility for RECLAIM purposes.

-**Rules 2011 and 2012 - Typographical Edits**

Staff also proposes to make several typographical clarifications and corrections in Rules 2011 and 2012 Appendix A, Attachment C B.2.b and Rule 2011 Appendix A, Attachment C B.2.e. Please see Appendix X for further explanations.

Draft Program Environmental Assessment (PEA)

A Notice of Preparation/Initial Study (NOP/IS) was released for a 57-day public review and comment period from December 5, 2014 to January 30, 2015. Eight comment letters were received from the public regarding the preliminary analysis in the NOP/IS. These comment letters and responses to individual comments are included in Appendix G of the Draft Program Environmental Assessment (PEA). In addition, on January 8, 2015, a CEQA and Socioeconomic Scoping Meeting was held. CEQA comments raised at the Scoping Meeting have been summarized and responded to in Appendix H of the Draft PEA. Socioeconomic comments raised at the Scoping Meeting and in the two comment letters specific to socioeconomic issues received are addressed in the Draft Socioeconomic Analysis. The Draft PEA was released on August 13, 2015, and the commenting period was extended until October 6, 2015. The Draft Socioeconomic Analysis was released on September 9, 2015.

Draft Findings under California Health and Safety Code

California Health and Safety Code § 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report.

Necessity
A need exists to amend Rules 2002 – Applicability, 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), 2005 – New Source Review for RECLAIM, 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions (Protocol), and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions (Protocol) to seek additional emission reductions from RECLAIM relative to the 2012 AQMP (Control Measure CMB-01), to demonstrate BARCT equivalence pursuant to California Health and Safety Code §40440, and to make changes necessary for the ongoing administration of the program.

Authority
The AQMD Governing Board has authority to amend existing Rules 2001 – Applicability, 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), 2005 – New Source Review for RECLAIM, 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions (Protocol), and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions (Protocol), pursuant to California Health and Safety Code §§ 39002, 40000, 40001, 40440, 40440.1, and 40702.

Clarity
The proposed amended rules are written or displayed so that their meaning can be easily understood by the persons directly affected by them.

Consistency
The proposed amended rules are in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication
The proposed amended rules will not impose the same requirements as any existing state or federal regulations. The amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, AQMD.

Reference

By adopting the proposed amended rules, the AQMD Governing Board will be implementing, interpreting and making specific the provisions of the California Health and Safety Code §§ 39002, 40001, 40440 (a), 40440.1, 40702, and 40725 through 40728.5; and Title 42 U. S. C. Sections 7410 and 7511a.

Comparative Analysis

H&S Code §§ 40727 and 40727.2 require a written analysis comparing the proposed amended rule with existing regulations. The §40727.2 analysis is traditionally applied to source-specific rules requirements affecting equipment subject to a command-and-control regulatory approach. RECLAIM varies from this regulatory approach in that it is based on a mass cap approach with a declining balance. This regulatory program decreases emission credit holdings, which caps emissions at a facility, as opposed to application of equipment-specific requirements. Therefore, this comparative analysis differs from the traditional comparative analysis. A comparative analysis for the RECLAIM program was provided for Rule 2002, amended on January 7, 2005 (NOx RECLAIM sources) and November 5, 2010 (SOx RECLAIM sources).

A comparative analysis, as required by H&S Code §40727.2, compares individual pieces of equipment to any applicable standard. The key to this analysis is to demonstrate non-duplication of new or amended regulatory requirements on an affected source. The current proposed RECLAIM amendment primarily seeks to reduce RTCs in the market and NOx emissions. There are no significant changes proposed to the other program elements, such as enforceable procedures, operating parameters or work practice requirements. In addition, amendments to the monitoring, recordkeeping, and reporting requirements are administrative in nature, as they do not affect or otherwise change an emissions limitation or add a significant requirement. On this basis, this comparative analysis focuses only on the determination of a new BARCT standard for the equipment under RECLAIM.

Relative to the derivation of new BARCT standards, all of the equipment categories listed in Tables 1 and 3 of Rule 2002 were examined by staff and presented to stakeholders for comments and feedback. However, as shown in Table 3.1 of this staff report, new BARCT was only determined for fluid catalytic cracking units, refinery boilers and heaters greater than 40 million British thermal units per hour (mmbtu/hr), refinery gas turbines, coke calciner, sulfur recovery units/tail gas incinerators, cement kilns, container glass melting furnaces, sodium silicate furnace, heat treating furnaces greater than 150 mmbtu/hr, non-refinery gas turbines, and internal combustion engines. In making the BARCT determinations, as discussed in Appendices A through S, a systematic approach of analysis was undertaken to derive any new control standards. This analysis included review of potentially applicable requirements from other air pollution control districts or agencies, applicable AQMD rules, as well as emission controls achieved in practice or otherwise technologically and economically feasible that would have otherwise been required under a command-and-control regulatory approach in the absence of RECLAIM. The results of the BARCT analysis are presented by equipment category in Appendices A through S.

The proposed programmatic reductions are based on the determination of new BARCT for certain emission sources. The resulting equipment-level reductions that would have occurred if applied with the same percentage under a command-and-control regulatory program are subsumed and spread among the RECLAIM facilities which hold 90 percent of the RECLAIM Trading Credits (RTC). The RTCs are proposed to be reduced at a rate of 66 percent for the larger refineries and investors and 49 percent among the remaining facilities that comprise those facilities holding 90 percent of the RTCs. As RECLAIM is a market-based program with facility-level mass emissions caps there are no specific air pollution control requirements (i.e., equipment specific emission limits) for these sources that must be met by these RECLAIM facilities holding 90 percent of the RTCs. Facilities are allowed the flexibility to meet their reduction requirements by whatever means they choose, such as equipment modifications, installation of control equipment, or purchasing RTCs.

Notwithstanding the aforementioned discussion, RECLAIM facilities are subject to the requirements of other AQMD regulations not subsumed by the program, including requirements under Regulation II – Permits, and Regulation IV – Prohibitions, such as Rule 401 – Visible Emissions, Rule 402 – Nuisances, and Rule 403 – Fugitive Dust. It should be noted that there are federally mandated programs, such as New Source Review (BACT/LAER), Prevention of Significant Deterioration, and Standards of Performance for New Stationary Sources, which are also applicable to the RECLAIM program and incorporated within the program. RECLAIM also complies with federal policy regarding start-up, shutdown, and malfunctions. In addition, there is not a comparable state or federal program for a cap and declining balance of NOx emissions. However, RECLAIM, as it currently exists, is in the SIP and complies with federal requirements applicable to market-type air pollution control programs, such as the Economic Incentive Program (EIP) guidelines.

Consequently, RECLAIM stands on-its-own and does not contain any duplicative or conflicting regulatory requirements.

Incremental Cost-Effectiveness

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option that would achieve the emission reduction objective of the proposed amendments, relative to NOx. The proposed control option is what was analyzed in the BARCT analysis, while the alternative control option is BARCT control to a less stringent level.

To determine the incremental cost effectiveness, the calculated difference in the dollar cost between the two control options is divided by the difference in their emission reduction potentials.

The control costs for the staff proposal used the average cumulative present worth values for each source category. The control costs for the alternative project used the same costs for the control equipment because it is assumed that a majority of the same costs to build and construct a control system despite a higher emission level would still apply.

The emission reductions of the alternative project are calculated by using the higher BARCT level applied to each source category. The emission reductions of the proposed control option are also factored into the final calculation.

The difference of the PWV of the alternative control option and the proposed control option (the PWV is the same in this case) is divided by the difference in the emission reduction potentials for both projects. If “a” is the alternative control option and “p” is the proposed control option, then the incremental cost effectiveness is:

$$(C_a – C_p) / (E_a – E_p) = \$ \text{ costs /per ton}$$

When calculated across all the source categories subject to BARCT for NOx RECLAIM, the incremental cost effectiveness for the source categories ranged from $53,000/ton to $917,000/ton. The table below lists the incremental cost effectiveness values calculated for all the source categories subject to the BARCT analysis.

Source Category	**Incremental Cost Effectiveness ($/ton)**
FCCUs	$117,000
Refinery Gas Turbines	$60,000
Boilers/Heaters >40 MMBTU/hr	$61,000
Coke Calciner	$897,000
SRU/TG Incinerators	$63,000
Container Glass Melting Furnaces	$78,000
Sodium Silicate Furnace	$122,000
Metal Heat Treating Furnace >150 MMBTU/hr	$61,000
Non-Refinery, Non-~~Electrical~~ Electrcity Generating Facility Gas Turbines	$917,000
Non-Refinery, Non-~~Electrical~~ Electrcity Generating Facility IC Engines	$53,000

The calculated values clearly indicate that the alternative control option is not viable when compared to the proposed controls.

Part I – BARCT Analyses for Refinery Sector

Part I contains the information related to the BARCT analyses for the refinery sector. Part I includes 10 Appendices from Appendix A to Appendix J that discuss 1) the NOx control technologies, 2) costs and cost effectiveness analyses for major NOx sources at the refineries, and 3) the consultant's analyses. The NOx reductions co-benefits of the energy efficiency projects at the refineries are summarized in Appendix K. The Survey Questionnaires sent to the refineries in ~~2003~~ 2013 to collect pertinent information for this BARCT analyses are included in Appendix L.

Appendix A - Refinery Fluid Catalytic Cracking Units

Process Description

There are five refineries that operate six fluid catalytic cracking units (FCCU) in the SCAQMD: Chevron, ExxonMobil, Tesoro (Carson and Wilmington), Phillips66, and Valero. The FCCUs are classified as major sources of emissions in RECLAIM, and as such, the NOx emissions from FCCUs are required to be monitored with a continuous emission monitoring system (CEMS), and reported on a daily basis electronically to the SCAQMD. A brief description of the process is presented below.

An FCCU converts heavy oils into more valuable gasoline and lighter products. A schematic of the process is shown in Figure A.1. The process uses a very fine catalyst that behaves as a fluid when aerated with a vapor. The fluidized catalyst is circulated continuously between a reactor and a regenerator and acts as a vehicle to transfer heat from the regenerator to the oil feed in the reactor. The cracking reaction is endothermic and the regeneration reaction is exothermic. The fresh feed is preheated by heat exchangers to a temperature of 500-800 degrees Fahrenheit and enters the FCCU at the base of the feed riser where it is mixed with the hot regenerated catalyst. The heat from the catalyst vaporizes the feed and raises it to the desired reaction temperature. The mixture of catalyst and hydrocarbon vapor travels up the riser into the reactor. The cracking reaction starts in the feed riser and continues in the reactor. Average reactor temperatures are in the range of 900-1,000 degrees Fahrenheit. As the cracking reaction progresses, the catalyst surface is gradually coated with carbon (coke), reducing its efficiency. While the cracked hydrocarbon vapors are routed overhead to a distillation column for separation into lighter components, the oil remaining on the catalyst is removed by steam stripping before the spent catalyst is cycled to the regenerator.

In the regenerator, spent catalyst is reactivated (regenerated) by burning the coke off the catalyst surface. The regenerated catalyst is generally steam-stripped to remove adsorbed oxygen before being cycled back to the reactor. The regenerator exit temperatures for catalyst are about 1,200-1,450 degrees Fahrenheit. The regenerator can be designed and operated to either partially burn the coke on the catalyst to a mixture of carbon monoxide (CO) and carbon dioxide (CO_2), or completely burn the coke to CO_2. The regenerator temperature is carefully controlled to prevent catalyst deactivation by overheating and to provide the desired amount of carbon burn-off. This is done by controlling the air flow to give a desired CO_2/CO ratio in the exit flue gases or the desired temperature in the regenerator. The flue gas containing a high level of CO is routed to a supplemental-fuel fired CO boiler if needed to completely burn off the CO to CO_2. The FCCUs in the SCAQMD are currently operated in a completely burn mode; what used to be the CO boilers are used as heat recovery devices without any supplemental fuel.

It is during the regeneration cycle that some of the catalyst is lost in the form of catalyst fines, and NOx, SOx and other pollutants are formed. The FCCU is a major source of sulfur oxides (SOx), nitrogen oxides (NOx), particulate matter (PM10, PM2.5), as well as ammonia (NH3), hydrogen cyanide (HCN) and other pollutants in the refinery. Approximately 90% of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is then burned-off in the regenerator. This portion of the NOx is called "fuel" NOx. "Fuel" NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10% of the NOx generated from the FCCUs are "thermal" NOx which is generated in the high temperature zones in the regenerator, and "prompt" NOx generated from the reaction between nitrogen and oxygen in the combustion air. The NOx emissions from the FCCU are typically controlled with selective catalytic reduction (SCR), LoTOx scrubbers, and/or NOx reducing additives.

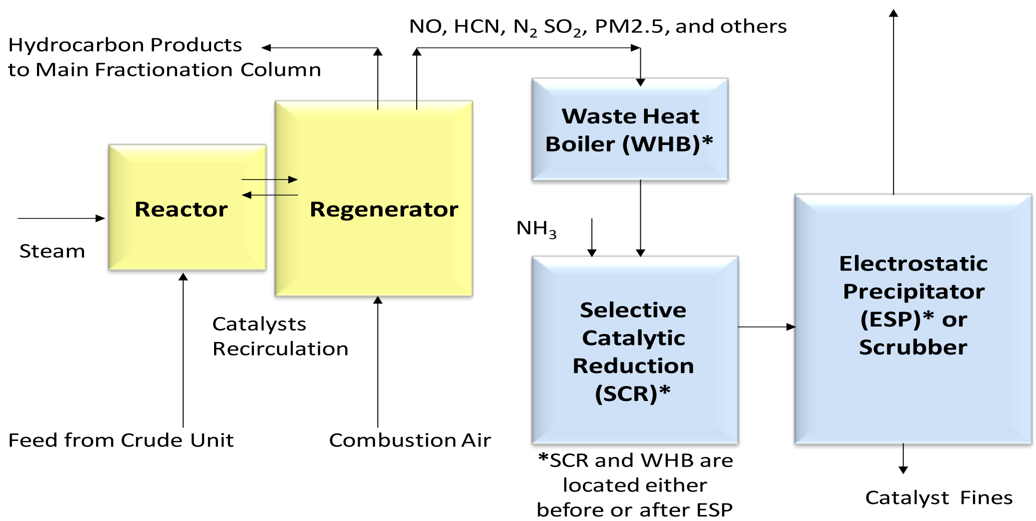


Figure A. 1 - Simplified Schematic of FCCU Process

Emission Inventory

As shown in Table A.1, the total 2011 NOx emissions from the six FCCUs (two with downstream CO boilers/heat exchangers) located in the SCAQMD are 1.08 tons per day.

Three FCCUs at Refinery 6, 1 and 5 use SCRs installed in 2000, 2003 and 2008, respectively to control NOx emissions. Three FCCUs at Refinery 4, 7 and 9 have no NOx controls.

As shown in Table A.1, Refinery 1's FCCU with SCR currently emits at a level under 2 ppmv NOx (with a 5 ppmv ammonia slip.) The NOx concentrations from other FCCU/CO units vary from 6 to 45 ppmv. Figure A.2 graphically shows the 2011 NOx emissions and the regenerator exhaust gas NOx concentrations for the six FCCUs in the SCAQMD. Comparing the data of the six FCCUs, Refinery 1's FCCU operating with SCR installed in 2003 has the lowest NOx emissions and the lowest NOx concentrations at below 2 ppmv.

As previously mentioned, 90% of the NOx emissions from the FCCUs are generated from the nitrogen in the FCCU feed (or coke in the regenerator.) Figure A.3 shows the NOx emissions compared to the FCCU feed rates. Comparing the data of the six FCCUs, Refinery 1 has the highest feed rate but achieves the lowest emissions with the use of an SCR.

Table A. 1 - 2011 Emissions for Refinery FCCUs

Facility ID	Device ID	Device	Process/NOx Control	2011 Emissions (lbs)	Current NOx ppmv @ 3% O2
5	203	REGEN1	FCCU/SCR	119,724	14.84
1	164	REGEN2	FCCU/SCR	16,686	1.21
6	151	REGEN3	FCCU/SCR	123,008	5.62
6	164	CO BOILER	FCCU/SCR	20,038	5.62
4	112	CO BOILER	FCCU/no control	157,150	21.0 - 27.6
4	96	REGEN4	FCCU/no control	in CO Boiler	21.00
7	1	REGEN5	FCCU/no control	101,648	12.88
9	36	REGEN6	FCCU/no control	249,277	35.5 - 45
			Total	**1.08 tons per day**	

Achieved-In-Practice Level for FCCU

Refinery 1 FCCU's SCR has demonstrated that a level of 2 ppmv NOx at 5 ppmv ammonia slip is achieved in practice. [Reference 1]

— The SCR was installed and operated since 2003. It was designed with a NOx inlet of 155 ppmv to achieve a level of 10 ppmv NOx outlet concentration (>90% control efficiency)

— At normal operations, the inlet NOx concentrations range from 40 - 80 ppmv, and the outlet NOx concentrations are typically below 2 ppmv with 5 ppmv ammonia slip (95% - 98% control efficiency). The SCR is capable of having three catalyst layers, each 29 ft x 29 ft x 4.5 ft deep; and is operated with two layers to reach 95% - 98% control. Catalyst life is 5 to 6 years.

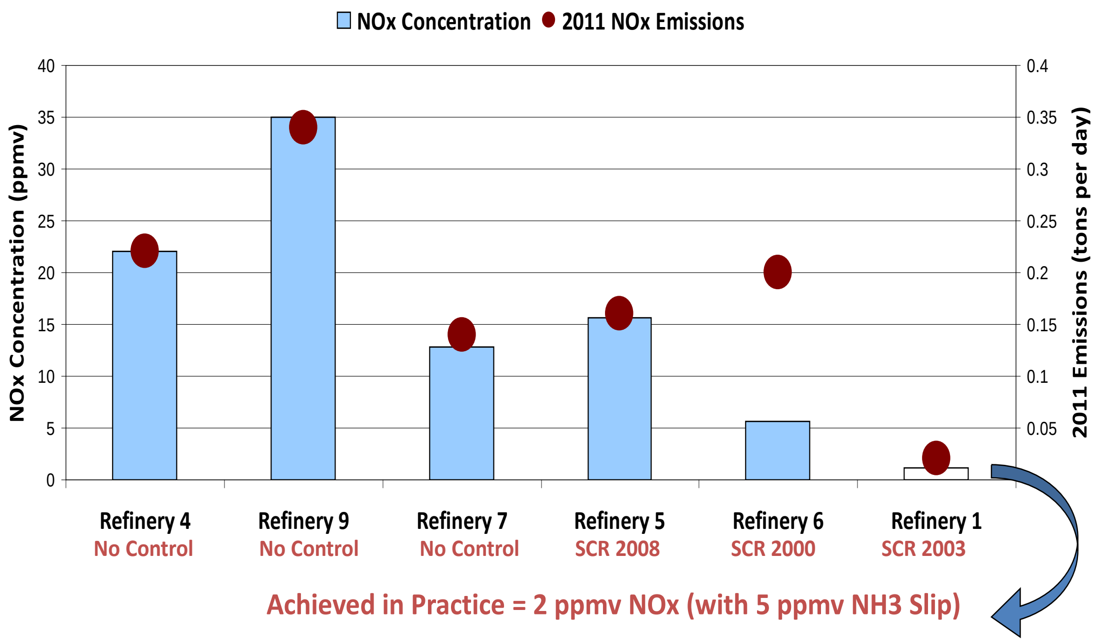
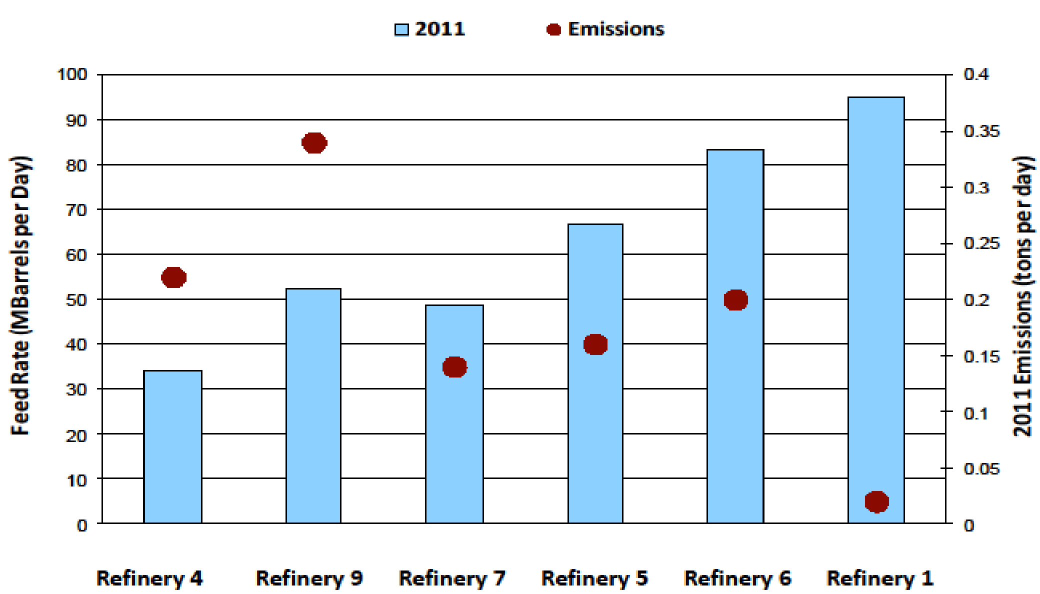


Figure A. 2 - 2011 NOx Emissions and NOx Concentrations for Refinery FCCUs



Note: Refinery feed rates are from source test reports and the U.S. Energy Information Administration Website – Refinery Capacity Report www.eia.gov

Figure A. 3 - 2011 NOx Emissions and Feed Rates for Refinery FCCUs

Control Technology

The commercially available control technologies for NOx are discussed below.

Selective Catalytic Reduction (SCR)

For the past two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. SCRs can be designed to reduce 95%-98% NOx emissions from the FCCUs and achieve 2 ppmv NOx while maintaining a low ammonia slip of less than 5 ppmv. [1-17]

SCR is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions: [2 - 4]

$4\ NH_3 + 4\ NO \rightarrow 4\ N_2 + 6\ H_2O$ (Reaction 1)
$4\ NH_3 + 2\ NO + 2\ NO_2 \rightarrow 4\ N_2 + 6\ H_2O$ (Reaction 2)

It should be noted that, at temperatures above 797 ^oF, ammonia can be oxidized to form NO and N_2O. These are undesirable reactions since NO and N_2O will ultimately convert to NOx and increase the NOx emissions. [5]

$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O$ (Reaction 3)
$4\ NH_3 + 4\ NO + 3\ O_2 \rightarrow 4\ N_2O + 6\ H_2O$ (Reaction 4)

A successful SCR catalyst can facilitate the reduction of NH_3 (Reaction 1 and 2) while subsiding the NH_3 oxidation reactions (Reaction 3 and 4). Typically, the SCR catalysts are vanadium, titanium, and/or zeolite based with different sizes and shapes, and have various ranges of operating temperatures: [5 – 8, 18]

Conventional SCR catalysts:	400 degrees F - 800 degrees F
Low temperature SCR catalysts:	300 degrees F - 400 degrees F
High temperature SCR catalysts:	800 degrees F - 1100 degrees F

The ~~stochiometric~~stoichiometric amount of ammonia required is 1 mole of NH_3 per mole of NOx reduced (NH_3/NOx = 1). Ammonia injection and mixing are critical since a non-uniform distribution and mixing of ammonia can result in inadequate NOx conversion and extensive ammonia slip.

To reduce the ammonia slip caused by imperfect ammonia distribution and mixing, SCR manufacturers have developed the Ammonia Slip Catalyst (ASC), a layer of catalyst which can be installed downstream of the SCR catalyst. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The current newly developed ASCs selectively favor the NH_3 reduction over the NH_3 oxidation: NH_3 is partially oxidized to NO (Reaction 3) and NO is then quickly reduced to N_2 (Reaction 1 and 2). In addition, the advanced ACSs highly support the oxidation of CO to CO_2. Other advantages of ASCs are summarized below: [5, 9-10]

- Enhancing the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx;
- Allowing for operations at higher NH_3/NOx ratios to ensure complete NOx conversion;
- Maintaining low ammonia slips; and
- Reducing the overall SCR catalyst volume while maintaining the high NOx control efficiency.

In the SCAQMD, aqueous ammonia is required to be used with SCRs instead of anhydrous ammonia due to safety reasons. In general, aqueous ammonia has lower risks and higher operating costs than anhydrous ammonia. A larger volume of aqueous ammonia will be required to achieve the same NOx reduction, thus increasing the costs of deliveries (e.g. for 29% aqueous ammonia, the delivery costs is in transporting 71% water with the ammonia.) Aqueous ammonia requires either compressed air for atomization or vaporizers to evaporate the water. The costs for operating with aqueous ammonia are approximately two times higher than the costs for operating with anhydrous ammonia. [11-13]

Sulfur dioxide (SO_2) to sulfur trioxide (SO_3) conversion and ammonium bisulfate (ABS) formation are undesirable reactions in the SCR process. SO_3 and ABS can cause plugging at downstream components. However, the main factors affecting the formation of ABS, such as temperature, the amount of ammonia slip, molar ratio of ammonia to NOx, the SO_3 concentrations, and fly ash contents; and the methods to control SO_3 ABS formation to reduce its negative effects have been well investigated, documented, and implemented by the SCR manufacturers as well as the SCR users. In addition, ABS is unlikely to be a problem for low flue gas sulfur units. [14]

LoTOx™ Application with Scrubber

LoTOx™ stands for "Low Temperature Oxidation" process in which ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds. These soluble compounds can then be removed by absorption in caustic solution, lime or limestone. The LoTOx™ process is a low temperature operating system, optimally operating in a range of 140 - 325 degrees F. The LoTOx™ is a registered trademark of Linde LLC. (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. The LoTOx application is explained below. [19 - 27]

A typical combustion process produces about 95% NO and 5% NO_2. Both NO and NO_2 are relatively insoluble in aqueous solution, and thus a wet gas scrubber is not efficient in removing these insoluble compounds from the flue gas stream. However, with the introduction of ozone, NO and NO_2 can be easily oxidized to highly soluble compounds N_2O_5 (Reaction 5 and 6) and subsequently converted to nitric acid HNO_3 (Reaction 7). The nitric acid is then rapidly absorbed in caustic solution (Reaction 8), limestone or lime (Reaction 9 and 10), and removed from the wet scrubbers. In addition, the rates of oxidizing reactions for NOx (Reaction 5 and 6) are fast compared to SO_2 oxidation reaction (Reaction 11), and as a result, there is no ABS or SO_3 formation. The LoTOx process can be integrated with any types of wet scrubbers (e.g. venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs).

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 - Fast)
$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$	(Reaction 7)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 - Very slow)

The LoTOx process requires oxygen supply and ozone generation. Oxygen is used to generate ozone on site. Typically oxygen is stored as liquid in vacuum jacketed vessels or is delivered by pipeline. Ozone is an unstable gas and it is typically generated on demand using an ozone generator. An ozone generator is shaped similar to a shell and tube heat exchanger. A corona discharge is used to dissociate oxygen into individual atoms; and the oxygen atoms combine with other oxygen molecules to form ozone. An ozone injection manifold should be designed to achieve uniform distribution and complete mixing. A ratio of NOx/O_3 of about 1.75 – 2.5 is needed to achieve 90% to 95% NOx conversion and reduction. Since sulfites are ozone scavengers, the LoTOx process typically has a very low ozone slip of 0-3 ppmv.

Several advantages of LoTOx application in comparison to SCR are:

- LoTOx is a low temperature operating system, meaning that it does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases.

- LoTOx can be an integrally connected to a wet (or semi-wet) scrubber, and become a multi-component air pollution control system that can reduce NOx, SOx and PM in one system whereas SCR is primarily designed to reduce only NOx

- There is no ammonia slip, SO_3, and ABS issues associated with LoTOx application.

BOC Gases received a grant funded partially by the California Air Resources Board to demonstrate the LoTOx technology at a reverbertory furnace used for lead smelting, operated by Quemetco Inc., City of Industry in California. The demonstration was successful, accomplishing > 90 percent NOx removal which led to a full scale system installation in 2001.[23] Today, there are more than 50 applications engineered by Linde since 1997,[19] and more than two dozen applications with EDV™ scrubbers engineered by BELCO since 2007.[26] EDV™ is a registered trademark of BELCO. LoTOx with EDV™ scrubber is shown in Figure A.4.

Table A.2 contains a list of the LoTOx applications for FCCUs, boilers, furnaces, and other combustion equipment. This is not an inclusive list. Applications in gas-fired and high sulfur coal-fired units met 95% control (2 ppmv - 5 ppmv). Current installations in refineries have achieved NOx level of 8 ppmv -10 ppmv (85% - 95% control efficiency). Manufacturers have confirmed that LoTOx can be designed to achieve 2 ppmv NOx from current inlet concentrations (85%-95% control efficiency) for FCCUs.

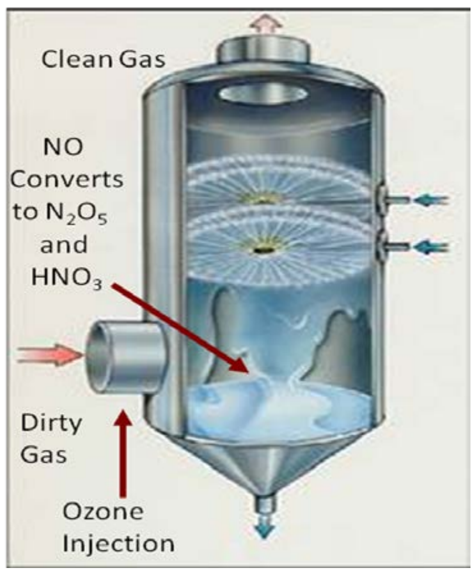


Figure A. 4 - EDV Scrubber with LoTOx Application

Table A. 2 – List of LoTOx Applications

No	Application	Exhaust Gas Flow (scfm)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1	400 HP natural gas fired boiler *	4,000	30-70	2	97%	1997-98
2	Stainless steel pickling	4,000	3400	100	97%	2000
3	25 MW coal fired boilers	90,000	200	10-20	95%	2001
4	Lead recovery furnace	26,000	50-150	10	93%	2002
5	1000 HP natural gas fired boiler *	10,000	20-40	4	90%	2001
6-10	Five (5) FCCUs in the U.S.	40,000-260,000	70-120	8-20	80%	2007
11-12	Sulfuric acid plants in the U.S.	2 x 16,800	90	10	90%	2008
13-23	Nine (9) FCCUs and 2 LoTOx ready installations in the U.S.	12,000 – 310,000	30-250	10-18.5	93%	2008-15
24-40	Ten (10) FCCUs, a refinery boiler, 6 LoTOx ready installations in China	90,000-390,000	100-350	20-73	80%	2012-15
41-42	FCCUs in Thailand & Romania	43,000-135,000	230-250	20-73	80%	2015-19

Note: See Reference 19. * Units are in Southern California.

NOx Reduction Additives

The combustion in the FCCU regenerator generates a dozen of various pollutants (NO, N_2O, NO_2, HCN, NH_3, CO, SO_2 ~~etc~~etc.) and the dynamic interaction of these compounds with each other is complex. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure A.5. “Fuel” nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, NO_2 compounds. The rates of these reactions depend heavily on the regenerator temperatures and the regenerator configuration. NOx reduction additives can be used to promote the conversion of NOx, HCN, and NH_3 to N_2 and reduce NOx emissions. The removal efficiency for NOx Reduction Additives is reported to vary from 50% to 80%. [28-38]

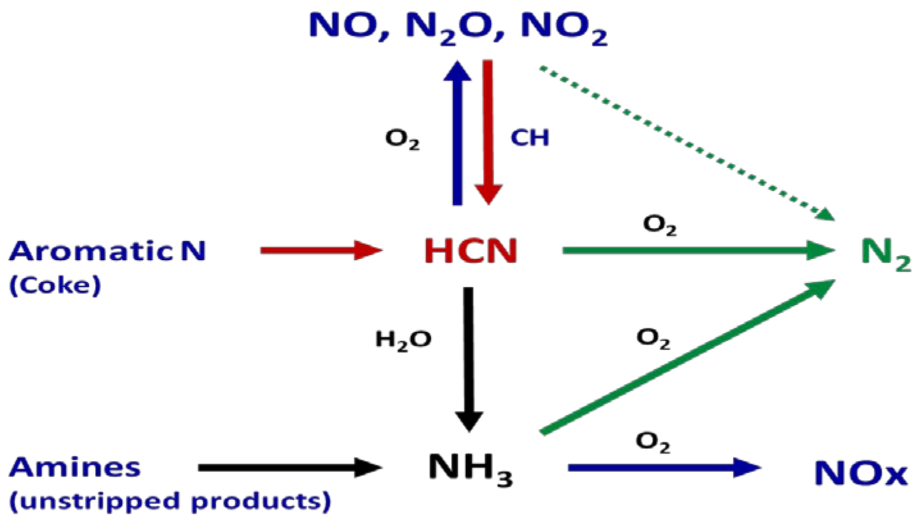
No	Application	Capacity (bpsd)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1	FCCU, Arkansas	20,000	70-100	10	86%	2007
2	FCCU, Texas City, TX	130,000	100-200	10	95%	2007
3	FCCU, Texas City, TX, retrofit	60,000	100-150	8	95%	2007
4	FCCU, Texas City, TX, retrofit	52,000	70-100	10	90%	2007
5	FCCU, Houston, TX, retrofit	58,000	100-150	10	93%	2007
7	FCCU, St. Charles, LA, retrofit	100,000	Confidential			2010
8	FCCU, Corpus Christi, TX, retrofit	45,000				2010
9	FCCU, Delaware, DE, retrofit	75,000				TBD
10	FCCU, El Dorado, KS	40,000	150	20	86%	TBD
11	FCCU, Ardmore, Oklahoma	40,000	TBD			TBD
12	FCCU, Three Rivers, Texas	28,000				TBD
13	FCCU, Placid Refining, LA	30,000				TBD

Note: Refer to Reference 20 for additional installations inside and outside of the U.S. Some scrubbers have built in ready for LoTOx retrofit but ozone generators have not yet been installed as of May 2013.

Manufacturers of the NOx reduction additives such as BASF, INTERCAT and Grace Davidson recommended the following best practices to minimize the NOx formation with the use of their additives, and at the same time, promote the conversion of CO to CO2:

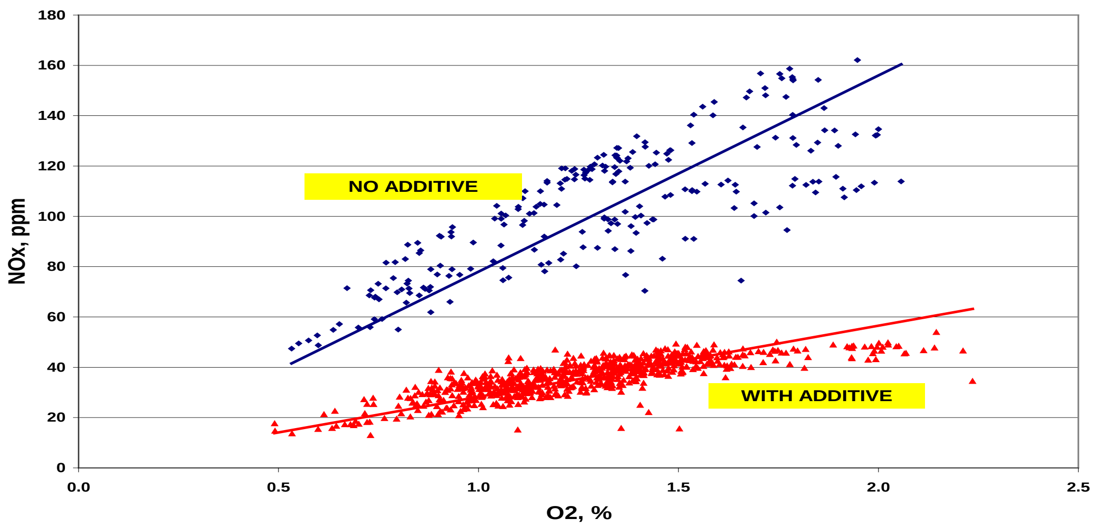
- Minimizing excess oxygen,
- Reducing feed nitrogen, and
- Utilizing non-platinum CO promoters

Figure A.6 shows outlet NOx concentrations of a FCCU with and without the use of NOx Reduction Additives. Data in Figure A.6 shows that higher excess oxygen favors the formation of NOx rather than N_2, and NOx Reducing Additives are capable of removing 60% of NOx emissions. NOx Reduction Additives cannot yet reduce NOx to 2 ppmv levels, however additives may be used in combination with other control technologies to reach the targeted levels. Two manufacturers indicated that NOx additives generally would cost about $15-$20 per pound and would be used at a rate between 1-3% of the FCC fresh catalyst addition rate. The NOx control effectiveness of the NOx Reducing Additives would be very specific for each FCCU application.



(Picture taken from References 22 and 23)

Figure A. 5 - Nitrogen Chemistry in the FCC Regenerator



(Picture taken from Reference 22)

Figure A. 6 - NOx Reduction Additive Reduces NOx Emissions by 60%

Costs and Cost Effectiveness for SCRs

Several methodologies were used to estimate the costs and ensuing cost effectiveness of installing or modifying the SCR's for the FCCU controls to 2 ppmv NOx. These included direct cost estimates from refiners, scaling cost estimates based on flue gas flow rates, using U.S. EPA's guideline approach, an upper range industry cost factor and a consultant's independent assessment.

Refinery 1

The refinery 1 SCR achieved 2 ppmv NOx and 5 ppmv NH_3 slip. Refinery 1 provided staff with the total installed costs, ammonia costs, and catalysts replacement costs for their SCR. [1] Staff estimated Present Worth Value (PWV) for Refinery 1 SCR using the equations below assuming 4% interest rate and 25-years SCR life. The PWV of Refinery 1 SCR was estimated to be $41 million dollars.

$$PWV_{Ref\ 1} = TIC_{Ref\ 1} + (15.62 \times AC_{Ref\ 1}) + (2.52 \times CR_{Ref\ 1}) \qquad \text{(Equation 1)}$$

Where:

$PWV_{Ref\ 1}$ = Present Worth Value, $
$TIC_{Ref\ 1}$ = Total Installed Costs, $
$AC_{Ref\ 1}$ = Annual Operating Costs, $
$CR_{Ref\ 1}$ = Catalysts Replacement Costs, $

Refinery 5, 6 and 7

Costs for the SCRs at Refineries 5, 6 and 7 were derived based on Refinery 1's data. The PWV of Refinery 5, 6, and 7 SCRs were estimated using the PWV of Refinery 1 SCR and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power as follows. The PWVs of SCRs for Refinery 5, 6 and 7 were estimated to be $33 million, $57 million and $27 million respectively as shown in Table A.3.

$$PWV_{Ref\ 5} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 5} / \text{Flow Rate}_{Ref\ 1})^{\wedge 0.7} \qquad \text{(Equation 2)}$$
$$PWV_{Ref\ 6} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 6} / \text{Flow Rate}_{Ref\ 1})^{\wedge 0.7}$$
$$PWV_{Ref\ 7} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 7} / \text{Flow Rate}_{Ref\ 1})^{\wedge 0.7}$$

Refineries 5 and 6 installed their SCRs in 2008 and 2000 respectively. In order to meet the 2 ppmv NOx proposed level, they may choose to 1) retrofit their existing SCRs, or 2) add additional catalysts to their existing SCRs if space is available (Note: Refinery 1 only utilizes 2 layers out of 3 layers of catalysts to meet 95% - 98% control), or 3) change the existing catalysts to a more effective catalyst type. As shown in Table A.3, the PWVs in these scenarios can be potentially less than \$33 million and \$57 million dollars for Refineries 5 and 6, respectively.

Refinery 4 and 9

Refinery 4 and Refinery 9 FCCUs have no controls for NOx emissions. Several manufacturers provided costs information for the SCRs at Refinery 4 and Refinery 9 to achieve 2 ppmv and 5 ppmv NOx.[15 - 17] One manufacturer indicated that the flue gas exist temperatures at the two refineries must be raised to 650 degrees F to avoid SO2/SO3 and ABS related problems; and estimated that this would add about 10% to the overall costs of the equipment.

The EPA's OAQPS Guidelines' approach was used to estimate the following costs: [4]

Instrumental = 10% x Equipment Cost
Sales Tax = 9% x Equipment Cost
Freight = 5% x Equipment Cost
Thus, Total Equipment Cost = 1.24 x Equipment Cost = 1.24 EC
Installed Costs = 50% of Total Equipment Costs

Total Installed Costs (TIC) = (1.24 EC) + 0.5(1.24 EC) = 1.86 EC (Equation 3)

Based on its reported data, the annual operating costs of Refinery 1's SCR during its 25-year life is about 20% of the total installed costs. Staff used this 20% factor to estimate the 25-year operating costs for the new SCRs at all the refineries. Staff added a contingency factor of 1.5 to cover additional uncertainties for both the TIC and the annual operating costs.

$PWV_{\text{Ref 4, Ref 9}}$ = 1.5 [(1.86 EC) + 0.2 (1.86 EC)] = 3.35 EC (Equation 4)

Using the EPA OAQPS Guidelines' approach, the PWVs would become \$16 million and \$19 million for Refinery 4 and 9 as shown in Table A.3, respectively.

Cost effectiveness (CE) was estimated as follows and is summarized in Table A.3:

CE = PWV / (ER x 365 days x 25 years) (Equation 5)
Where:

CE = Cost Effectiveness, \$/ton
PWV = Present Worth Value, \$
ER = Emission Reductions, tpd

The cost effectiveness in Table A.3 is estimated using Discounted Cash Flow (DCF) method. The cost effectiveness calculated based on the Levelized Cash Flow (LCF) method is about 1.65 times higher than the cost effectiveness estimated by the DCF method (e.g. $18K per ton DCF compared to $30K per ton LCF.)

Table A. 3 - Costs and Cost Effectiveness for SCRs (December 2014)

Fac ID	Emissions (tpd)	NOx (ppmv)	% Control	Emission Reduction (tpd)	PWV ($M)	CE ($/ton)
1	0.02	<2	95%	-	(41)	(10,181)
5	0.16	15	87%	0.14	< 33	< 25,259
6	0.20	6	64%	0.13	< 57	< 49,408
7	0.14	13	84%	0.12	27	25,455
4	0.22	21-23	91%	0.20	16	8,961
9	0.34	34-52	95%	0.32	19	6,537
Total reductions for Ref 4,9,5,6 and 7				**0.91**	**152**	**Avg <18,422**

Emissions for all 6 refineries = 1.08 tpd. Remaining emissions from FCCUs at BARCT for all 6 refineries = 1.08 – 0.91 = 0.17 tpd

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs

In 2014, staff contracted Norton Engineering Consultants (NEC) to conduct a BARCT analysis for the refinery sector. [39] The NEC's analysis is included in Addendum 1. Table A.4 shows a comparison between NEC's and staff's estimates:

Table A. 4 – Comparison of SCR Costs Estimated by Staff and NEC (December 2014)

Facility ID	Staff's Estimates (note 1) ($M)	NEC's Estimates ($M)	NEC's Feed Rate Adjusted Estimates ($M)
5	<33	<46 (note 2)	<43
6	<57	<46 (note 2)	<50
7	27	42 (note 3)	37
4	16	38	38
9	19	39	37
Total	**152**	**211**	**195**

Note: 1) Staff's estimates were presented at the Jan 22, 2014 Working Group Meeting. For a 2-layer SCR configuration; 2) Estimates reflect a new SCR installation and are over-estimated because the FCCUs already have SCRs installed; 3) This FCCU will be dismantled.

NEC recommended SCRs with 3 layers of catalysts compared with staff's analysis based on refinery FCCU SCR applications currently operating with 2 layers of catalyst in the Basin. The NEC cost estimate included 2 layers of markup factors applied to the equipment costs and an overall 4.5 factor to project the total installed cost to the cost of material and labor.[6] NEC further added the cost of waste heat boiler modifications, new CEMS and additional ammonia storage. The resulting cost information was used to generate a curve to express PWV as a function of feed rate.

NEC's initial estimation of PWV was conducted using a set of refinery FCCU feed rates that were not consistent with those reported in the 2010 SOx RECLAIM staff report or by the January 22, 2014 RECLAIM Working Group presentation. The third column in Table A.4 provides the adjusted cost estimate to account for the representative refinery feed rates.

Catalyst Layers

Staff used a different approach than NEC to estimate the SCR costs because Refinery 1 had achieved an emissions rate of 2 ppmv NOx with only 2 layers of catalysts. This resulted in a significant difference in the cost estimates based on 2 catalyst layers (staff) and 3 catalyst layers (NEC). To address this difference, staff adjusted the manufacture's proposed 60 barrels/day 3 catalyst-layer SCR configuration used by NEC in their estimate to a 2 catalyst-layer model. The adjustment included a 27 percent reduction in the base price to account for the 2-layer configuration (at 10 ft. per second) but then followed NEC's pricing including the 1.35 bid conditioning factor, the 1.75 labor factor and a 4.5 factor applied to the equipment cost. The adjusted estimate added the costs of the waste heat boiler modifications, additional ammonia storage, added CEMS, maintenance and catalyst replacement costs. The projected PWV for the adjusted manufacturers estimate for the 2-catalyst layer configuration is listed in Table A.5 totaling $163 million for five FCCU's.

Range of Costs and Cost Effectiveness for SCRs

In its report, NEC indicated that the factors in the EPA OAQPS Guidelines (Equation 3) were not sufficient to cover retrofitting applications at the refineries. The refineries also indicated the factors relating equipment costs to TIC should be at least 4, or higher. To reconcile this difference, staff presents the PWVs as a range of costs and cost effectiveness in Table A.5.

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[6] NEC first marked-up the costs provided by the manufacturer by 35%. NEC named this markup as "bid conditioning factor" to cover the "low" bid provided by the manufacturer. NEC then added 75% increase in labor costs to the costs provided by the manufacturer. NEC did not provide any references to their markup factors and simply stated that the factors were based on their own experience.

The staff cost effectiveness estimate is based on a 2-catalyst layer FCCU SCR application that is operating at Refinery 1. The PWV calculated for the five units totaled $152 million establishing the lower end average of the cost effectiveness at $18,000 per ton NOx reduced. The upper cost effectiveness listed in Table A.5 is derived from the PWV totals from the manufacturers adjusted 2-layer estimate averaging $20,000 per ton NOx reduced.

As previously stated, the 2-layer catalyst SCR application has been demonstrated to reach 2.0 ppmv at Refinery 1, in the Basin. Since NEC's proposed model is based on a 3-layer catalyst application it is not included in the cost effectiveness calculation presented in Table A.5. Regardless, the cost effectiveness calculated for the NEC model would place the FCCU SCR application for the 5 units at an average CE of $29,000. Thus, using the NEC 3-layer catalyst assumption, the cost effectiveness is still less than the $50,000 threshold used in the current BARCT analysis and less than the $30,800 threshold established for SCR control equipment established for boilers greater than 75 mmBtu/hr in SCAQMD Rule 1146.

Note that Refinery 4's FCCU is scheduled to be shut down in the near future which would result in lowering the costs estimated for the FCCU category.

Table A. 5 – Revised Costs and Cost Effectiveness for SCRs (March 2015)

Fac ID	Emission Red (tpd)	Staff's 2-Layer Estimate PWV ($M)	Manufacturers Adjusted 2-Layer With no Mark-Up Estimates ($M)	Manufacturers Ajusted 2-Layer with 2 Mark-Ups Estimates PWV ($M)	Range of PWV ($M)	CE ($/ton)
5	0.14	<33	<34	<36	<33 – 36	<25K - $27K
6	0.13	<57	<40	<42	<57 – 42	<49K – 36K
7	0.12	27	29	31	27 – 31	25K – 29K
4	0.20	16	22	23	16 – 23	9K – 13K
9	0.32	19	29	31	19 – 31	7K – 11K
Total	**0.91**	**152**	**154**	**163**	**152 - 163**	**18K – 20K**

Costs and Cost Effectiveness for NOx Reduction Additives

NOx reduction additives can reduce about 10% - 70% NOx emissions depending on the FCCU regenerator configuration and operating condition. The use of NOx reducing additives may not achieve the ultimate goal of 2 ppmv, but may help the refineries achieve the future facility overall shave. Cost effectiveness for NOx reducing additives were estimated to be about $6,460 per ton of NOx reduced using DCF method ($10,660 per ton using LCF method.) The inputs and results were summarized in Table A.6.[38]

Table A. 6 - Costs and Cost Effectiveness for NOx Reduction Additives

Inputs	
Baseline NOx	40 ppmv
NOx reduction	50%
Cost of NOx Reduction Additives	$15 per lb
NOx Reduction Additives	1.5% of total catalysts
Catalyst Addition Rate	4 ton per day
FCCU Rate	70 million barrels per day
Results	
NOx Reduction Additives Costs	1800 $/day
NOx Reduction	348 lbs/day
Cost Effectiveness for NOx Reducing Additives	**6,460 $/ton**

Costs and Cost Effectiveness for LoTOx Scrubbers

The FCCUs at Refinery 4 and Refinery 9 currently have no control. Refinery 7's FCCU has a scrubber. Process data for these three refineries' FCCUs were provided to a manufacturer, and the manufacturer provided estimates for the total installed costs and annual operating costs. [27]

The total installed costs provided by the manufacturer included the ozone generator, the associated closed loop chiller, cooling pump, ozone injection lances. The installed costs also included the associated platforms and access steel, some interconnecting piping and supports, valves and instruments and freight to the job site. The manufacturer did not include oxygen storage and vaporization (which was only necessary if the refinery did not yet have oxygen at the site for other uses), or the cost of electrical equipment and foundation. Staff added a contingency factor of 2 to markup the costs provided by the manufacturer to account for any additional modifications needed at the site and any variations in annual operating costs such as electricity or oxygen.

The PWV for Refineries 4, 7 and 9 LoTOx applications were estimated as follows:

$$PWV_{\text{Ref 4, 7 and 9}} = \text{Contingency Factor x } (TIC_{\text{Ref 4, 7 and 9}} + (15.62 \text{ x } AC_{\text{Ref 4, 7 and 9}}))$$

Where:

$PWV_{\text{Ref 4, 7 and 9}}$ = Present Worth Value $
$TIC_{\text{Ref 4, 7 and 9}}$ = Total Installed Costs provided by vendor, $
$AC_{\text{Ref 4, 7 and 9}}$ = Annual Operating Costs provided by vendor, $

Contingency Factor = 2

Refineries 5 and 6 currently employ SCRs to reduce their FCCU's NOx emissions. Scrubbers may be needed to reduce the SOx emissions from their FCCUs, and LoTOx can be installed concurrently with the scrubbers to further reduce NOx emissions. The PWV for LoTOx applications at Refineries 5 and 6 were estimated based on the PWV for LoTOx applications at Refineries 4 and 7 and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power as follows:

$PWV_{Ref\ 5} = PWV_{Ref\ 5} \times (\text{Flow Rate}_{Ref\ 5} / \text{Flow Rate}_{Ref\ 4})^{\wedge 0.7}$
$PWV_{Ref\ 6} = PWV_{Ref\ 7} \times (\text{Flow Rate}_{Ref\ 6} / \text{Flow Rate}_{Ref\ 7})^{\wedge 0.7}$

The present worth values and cost effectiveness values are summarized in Table A.7. The average cost effectiveness is $15 K per ton using DCF method and $25 K per ton using LCF method.

The manufacturer estimated that a plot space needed for the ozone generator and accessories to be about 25 ft x 35 ft. The first LoTOx application was put in service in 1997. At that time, required a large foot print (e.g. 1st generation LoTOx application at a Texas refinery required a foot print of 30 ft x 80 ft.) The newer generation LoTOx application has a much smaller footprint (e.g. an equivalent unit to the Texas refinery application now requires only 25 ft x 30 ft).

Table A. 7 - Costs and Cost Effectiveness for LoTOx Applications (December 2014)

Fac ID	Emissions (tpd)	NOx (ppmv)	% Control	Emission Reduction (tpd)	PWV ($M)	CE ($/ton)
4	0.22	21-23	91%	0.20	19	10,767[JW1]
7	0.14	13	84%	0.12	16	15,199
9	0.34	34-52	95%	0.32	32	10,631
5	0.16	15	87%	0.14	24	18,590
6	0.20	6	64%	0.13	34	29,502
Total for Ref 4,9,5,6 and 7				**0.91**	**125**	**Avg <15,124**

Staff did not include the costs for scrubbers and waste water treatment in Table A.7. Since Refinery 5 and 6 already have SCRs, they will likely to use their SCRs to control NOx. Staff included the costs for scrubbers with waste treatment for Refineries 4, 7 and 9. Staff also estimated the overall cost effectiveness for the LoTOx/scrubbing multi-component air pollution control as shown in Table A.8.

Table A. 8 – Revised Costs and Cost Effectiveness for LoTOx Scrubbers (March 2015)

Fac ID	NOx Emission Reductions (tpd)	SOx Emission Reductions (tpd)	PWV for LoTOx ($M)	PWV for Scrubbers ($M)	Total PWV ($M)	CE (K$/ton)
4	0.20	0.20	19	91	110	30
7	0.12	0.87	16	51	67	7
9	0.32	0.58	32	90	121	15

Note: 1) SOx emission reductions were taken from Table 3-11, Chapter 3, SOx RECLAIM Staff Report, dated November 2, 2010. [40] 2) PWVs for scrubbers including waste treatment were based on information provided on Table 3-12, Chapter 3, SOx RECLAIM Staff Report, dated November 2, 2010, and a Marshall Swift Index of 1.1. [40] 3) It is assumed that retrofitting existing scrubber for Refinery 7 would cost about half of the costs estimated for the installation of the new scrubber under SOx RECLAIM project.

Incremental Costs and Cost Effectiveness

The BARCT level for the FCCUs in 2005 was set at 85% reduction. The costs for SCRs to meet 85% reductions were estimated to be $111.1 million. The emission reductions were estimated to be 0.48 tons per day. A Marshall index of 1.25 was used to raise the costs of $111.1 million dollars to current dollars of $138.88 million.

Table A.9 presents the Staff estimated the overall PWVs for 2 cases:

Case 1: Assume all 5 refineries will use SCRs to achieve the proposed BARCT level of 2 ppmv. Using the low end costs for SCRs in Table A-5, the total PWVs to achieve 2 ppmv NOx level would be $152 million.

Case 2: Assume Refineries 5 and 6 will use SCRs (using the high end costs for SCRs in Table A.5) and Refineries 4, 7 and 9 will use LoTOx and scrubbers (Table A-8) for multi-component control. The total PWVs would be $375 million.

Table A. 9 – Present Worth Values of SCRs and LoTOx/Scrubbers for FCCUs (March 2015)

Fac ID	Case 1 - PWV ($M)	Case 2 - PWV ($M)
5	<33 (SCR)	<36 (SCR)
6	<57 (SCR)	<57 (SCR)
7	27 (SCR)	67 (LoTOx and Scrubber)
4	16 (SCR)	110 (LoTOx and Scrubber)
9	19 (SCR)	121 (LoTOx and Scrubber)
Total	**152 (all SCRs)**	**391 (SCRs and LoTOx/Scrubbers)**

Incremental cost effectiveness to achieve a more stringent of 2 ppmv NOx from a less stringent level of 85% control during 25-years life of the control device is listed in Table A.10. CE is estimated as follows:

$$CE_{\text{incremental}} = (PWV_{2\text{ ppmv}} - PWV_{85\%\text{ control}}) / ((ER_{2\text{ ppmv}} - ER_{85\%\text{ control}}) \text{ x } 25 \text{ yrs x } 365 \text{ days})$$

Where:

$CE_{\text{incremental}}$ = Incremental Cost Effectiveness, $/ton
$PWV_{2\text{ ppmv}}$ = Sum of all SCR (or LoTOx) costs to meet 2 ppmv, $
$PWV_{85\%\text{ control}}$ = Sum of all SCR costs to meet 85% reduction, $ = $139 M
$ER_{2\text{ ppmv}}$ = Total emission reductions achieved at 2 ppmv NOx, tpd
= 0.91 tpd estimated from 2011 baseline
$ER_{85\%\text{ control}}$ = Total emission reductions achieved with 85% control, tpd
= 1.08 tpd – 0.60 tpd = 0.48 tpd

Table A. 10 – Incremental Cost Effectiveness of SCRs and LoTOx Scrubbers for FCCUs (March 2015)

	Emission Reductions (tpd)	PWV ($M)
SCR for 85% control	0.48 tpd NOx	139
SCR for 2 ppmv for all 5 Refineries	0.91 tpd NOx	152
SCR for 2 ppmv for Ref 5, 6 and LoTOx/Scrubber for Ref 4,7, 9	0.91 tpd NOx and 1.65 tpd SOx	391
Case 1 – Incremental Emission Reductions = 0.91 – 0.48 = 0.43 tpd NOx Incremental Cost Effectiveness: SCR – SCR for all 5 Refineries (152 - 139) / (0.91 – 0.48) / 25 / 365 = 3,444 $/ton DCF and 5,683 $/ton LCF		
Case 2 – Incremental Cost Effectiveness: SCR – SCR for Ref 5, 6, and SCR - LoTOx for Ref 4, 7, 9 (391 – 139) / (0.91 + 1.65 – 0.48) / 25 / 365 = 13K $/ton DCF and 23K $/ton LCF		

Staff's Recommendation

Staff proposes a BARCT level of 2 ppmv NOx for FCCUs because 1) Refinery 1 FCCU's SCR has achieved-in-practice 2 ppmv NOx at 5 ppmv NH3 slip; and 2) NOx control technologies such as SCR, LoTOx, and NOx reduction additives are commercially available and can be used in conjunction to achieve 2 ppmv NOx in a cost-effective manner.

The cost information submitted by SCR and LoTOx manufacturers support that a BARCT level of 2 ppmv NOx is feasible and cost-effective for FCCUs in the SCAQMD. It should also be noted that NOx reducing additives, which can reduce 50% or more of NOx emissions, can be used in parallel with SCRs and LoTOx applications if needed.

In summary:

Case 1:
Total PWVs: $152 M with SCRs for all 5 refineries
Total incremental costs: $13 M
Incremental emission reductions: 0.43 tpd NOx
Incremental cost effectiveness with SCRs: 3,444 $/ton DCF or 5,700 $/ton LCF

Case 2:
Total PWVs: $391 M with SCRs for Refineries 5 and 6 and LoTOx/scrubbers for Refineries 4, 7 and 9
Total incremental costs: $252 M
Incremental emission reductions: 0.43 tpd NOx and 1.65 tpd SOx for 5 FCCUs
Incremental cost effectiveness: 13K$/ton DCF or 23K $/ton LCF

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Appendix B – Refinery Boilers and Process Heaters

Process Description

Boilers and process heaters are used extensively in almost all of the processes in refinery such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. Figure B.1 provides a simplified diagram of the processes where boilers and heaters are used. There are 23 boilers and 189 heaters in the refineries classified as major or large NOx sources. The refinery heaters and boilers primarily burn refinery gas which is generated at the refinery. Most of these boilers and heaters use natural gas as back-up or supplemental fuel. Liquid fuel or solid fuel is rarely used in refinery boilers and heaters. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

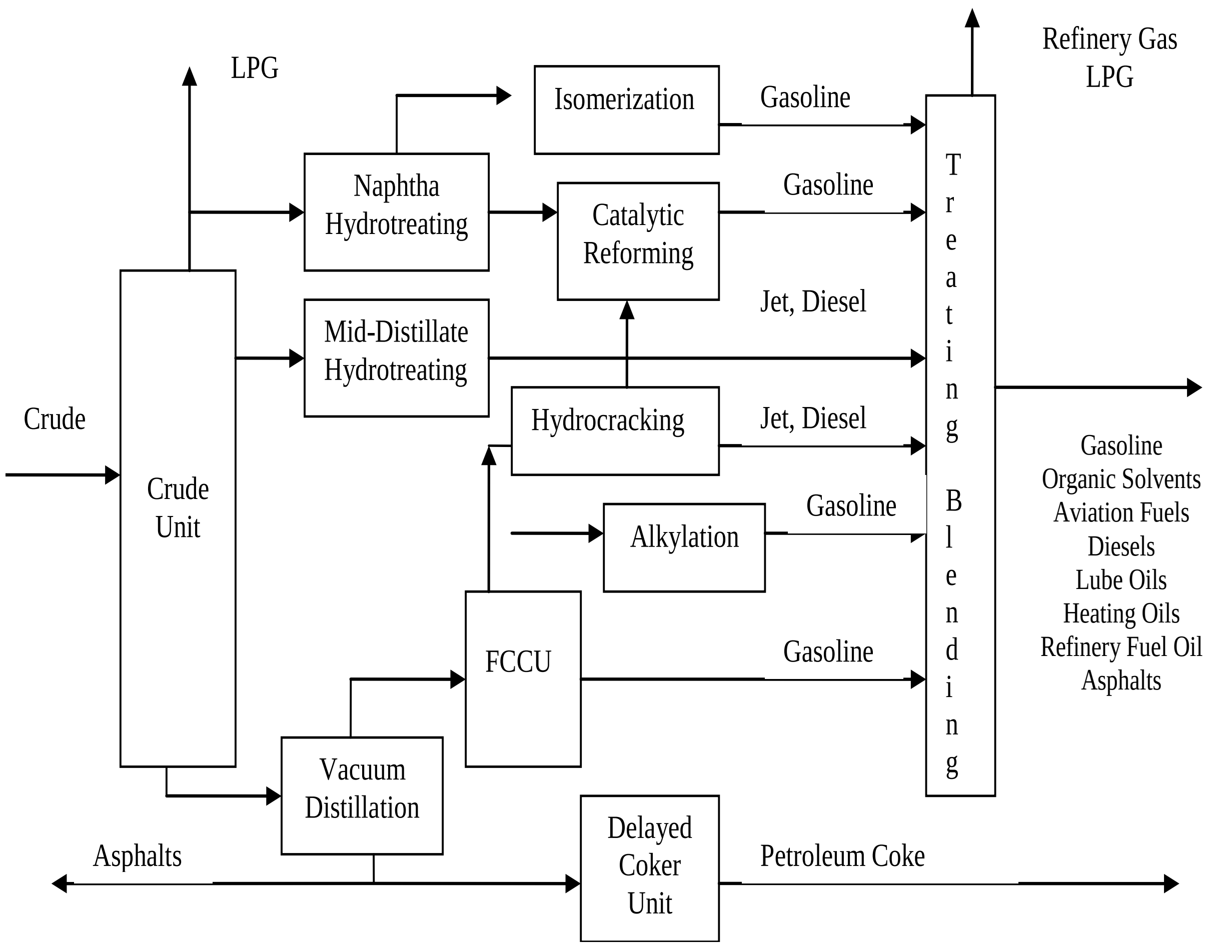

Figure B. 1 - Refinery Processes

Emission Inventory

There are a total of 212 boilers and heaters classified as major and large NOx sources at the refineries. The distribution of boilers and heaters and their emissions are shown in Table 5.1. Collectively, the 212 boilers and heaters emitted about 7.39 tons per day in 2011. Their NOx concentrations at the stack vary from 1.6 ppmv for units equipped with selective catalytic reduction (SCR) to 120 ppmv for units with no control.

The 2005 RECLAIM amendments set BARCT levels between 5 ppmv to 12 ppmv for various categories of boilers and heaters. A comprehensive list of equipment specific NOx emission limits is provided in Table 3 of the SCAQMD Rule 2002, amended January 7, 2005. As a component of the BARCT assessment, the decision was made to retain the 2000 BARCT level for boilers/heaters with maximum input rating between 40-100 mmBtu/hr at 25 ppmv. In 2005, it was estimated that 51 boilers/heaters would require SCRs to be installed to reduce NOx emissions. Only 4 pieces of equipment were retrofitted with SCRs; these were in response to either an EPA consent decree or an order of abatement. If all of the boilers and heaters had complied with the 2005 BARCT emissions from boilers and heaters would be reduced from 7.39 tons per day to 1.92 tons per day, approximately 74% reduction in emissions.

Achieved-In-Practice NOx Levels for Boilers and Heaters

The following is a summary of refinery boilers and heaters that have very low emission levels:

- Fourteen process heaters using refinery fuel gas in the SCAQMD ranging from 22 to 653 mmBtu/hr equipped with SCRs have achieved 1.6 - 3.5 ppmv NOx at 3% O_2;

- Two boilers, 400 HP and 1000 HP, using natural gas, equipped with LoTOx scrubbers have achieved 2 - 5 ppmv NOx at 3% O_2;

- A crude heater using refinery fuel gas rating at 10 mmBtu/hr in Coffeyville refinery Kansas has been operated at 3 - 8 ppmv NOx at 3% O_2 with Great Southern Flameless technology without the use of SCR.

All of the control technologies mentioned above are commercially available and can be designed to reach 2 ppmv NOx at 3% O_2.

Control Technology

Commercially available control technologies are SCRs, Great Southern Flameless Heaters, and LoTOx applications with scrubbers. Other potential technologies on the horizon are ClearSign, Cheng Low NOx and KnowNOx. SCR, Great Southern Flameless burners and ClearSign burner technologies are discussed below. Cheng Low NOx, LoTOx and KnowNOx technologies are discussed in other Appendices. Other common control technologies such as Low NOx burners, Ultra Low NOx burners, or Selective Non Catalytic Reduction (SNCR) are not discussed here.

Selective Catalytic Reduction

SCR is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions.

Great Southern Flameless Heaters

In 2012, Coffeyville Resources purchased the world's first flameless crude heater designed by Great Southern Flameless for their Coffeyville refinery in Kansas to comply with a Consent Decree issued by the U.S. EPA. The flameless heater has been in operation for over one year and has achieved-in-practice 5 ppmv NOx at 3% O2 with pilots in operation, and 3 ppmv NOx without pilots for flameless technology. Great Southern Flameless confirmed the following: [18-21]

- Flameless heaters can be designed to achieve:
  - 5 ppmv NOx at 3% O_2; or
  - 2 ppmv NOx at 3% O_2 with pilots off during flameless firing and with a fuel mix of 25% natural gas and 75% refinery gas.

- Oxy-fuel flameless heaters can be designed to achieve:
  - 2 ppmv NOx at 3% O_2; or
  - 1 ppmv with pilots off during flameless firing

Great Southern Flameless can supply flameless heaters or oxy-fuel flameless heaters with maximum rating from 10 mmBtu/hr to 320 mmBtu/hr (240 mmBtu/hr process duty.) Their production capacity is 30 heaters per year. The modules are designed and fabricated in Oklahoma, shipped in pieces to be field, and assembled at the site. The heaters can use the same foundation of the conventional heaters. The flameless heater designed by Great Southern Flameless for the Coffeyville refinery has the following characteristic:

- The heater is a polygon with the process coil (heat exchanger tubes) in the center and two "Flameless Nozzle Grouping" (FNG) located on the wall which fire tangentially. Each FNG consists of 2 conventional nozzles, 2 flameless fuel nozzles, 4 air nozzles and 1 nozzle for pilot fuel.

- To pin the flue gas in circulation against the wall, Great Southern Flameless developed and patented a proprietary design for the heater's interior wall. The interior wall of the heater has a dimple pattern in the refractory which holds the flue gas to the wall and allows the flue gas to circulate in high volume and velocity around the heater until it eventually rotates out to the center of the heater, and up through the uptake ducts and into the convection section of the heater. This unique wall design eliminates hot gas impingement on the process coil located in the center of the heater and assures even heat radiation from the heater walls to the heat exchanger tubes.

- Great Southern Flameless also developed and has a patent pending for an automated 3-way switching valve. This valve allows the heater to be operated in three different firing modes:
  - Conventional firing mode when all fuel gas is diverted to the 2 conventional nozzles;
  - Staged firing mode when half of the fuel gas goes to the 2 conventional nozzles and the other half goes to the 2 flameless nozzles; and
  - Flameless firing mode when all fuel gas goes to the 2 flameless nozzles and the combustion is sustained by the high temperatures of the combustion air.

- The heater has a balanced draft air-preheat system which generates high temperature combustion air. High temperature combustion air is required for the staged firing mode and the flameless firing mode to maintain the high auto-ignition temperature required for combustion.

From cold start, the heater is brought up in natural draft mode in the same manner as any typical conventional heater. The firing rate of the heater is gradually increased to the required level while the combustion air is gradually increased to 850 degrees F. Once the combustion air temperature exceeds 850 degrees F, it will sustain the automatic ignition of fuel, and the heater is transitioned into the staged fuel firing mode with pilots off-line. The heater is operated in the staged firing mode until steady state operation is achieved. At this point, the heater is transitioned into flameless firing mode. Visible flame from the conventional nozzles disappears and NOx emissions decreases significantly in the flameless mode operation.

Table B.1 below tabulates the temperature profile inside the heater under the three modes of firing. With more even temperature distribution, the flameless firing mode results in 4 ppmv NOx compared to 77 ppmv NOx under conventional firing and 49 ppmv under staged firing mode. The Coffeyville heater average NOx emissions are in the levels of 3 – 8 ppmvd without the use of high temperature high energy SCR system.

The heater can be designed for combustion with oxygen. Combustion with oxygen in place of air will eliminate "prompt" NOx and reduce CO_2 emissions. Figure B.2 shows a flameless heater modified for oxygen combustion. Table B.2 lists the predicted performance of an oxy-flameless heater. Flameless and oxy-flameless heaters come in modules and can be stacked up to 320 mmBtu/hr rating.

Table B. 1– Temperature Zones and NOx Emissions of Great Southern Flameless Heater

	Conventional Firing	Staged Firing	Flameless Firing
Combustion Air Temperature, degrees F	804	893	909
Average Radiant Upper Level Temp, degrees F	1544	1740	1714
Average Radiant Mid Level Temp, degrees F	2050	1826	1476
Average Radiant Lower Level Temp, degrees F	1488	1627	1669
Excess Oxygen, %	3.7	2.6	2.4
NOx, ppmv	77	49	4

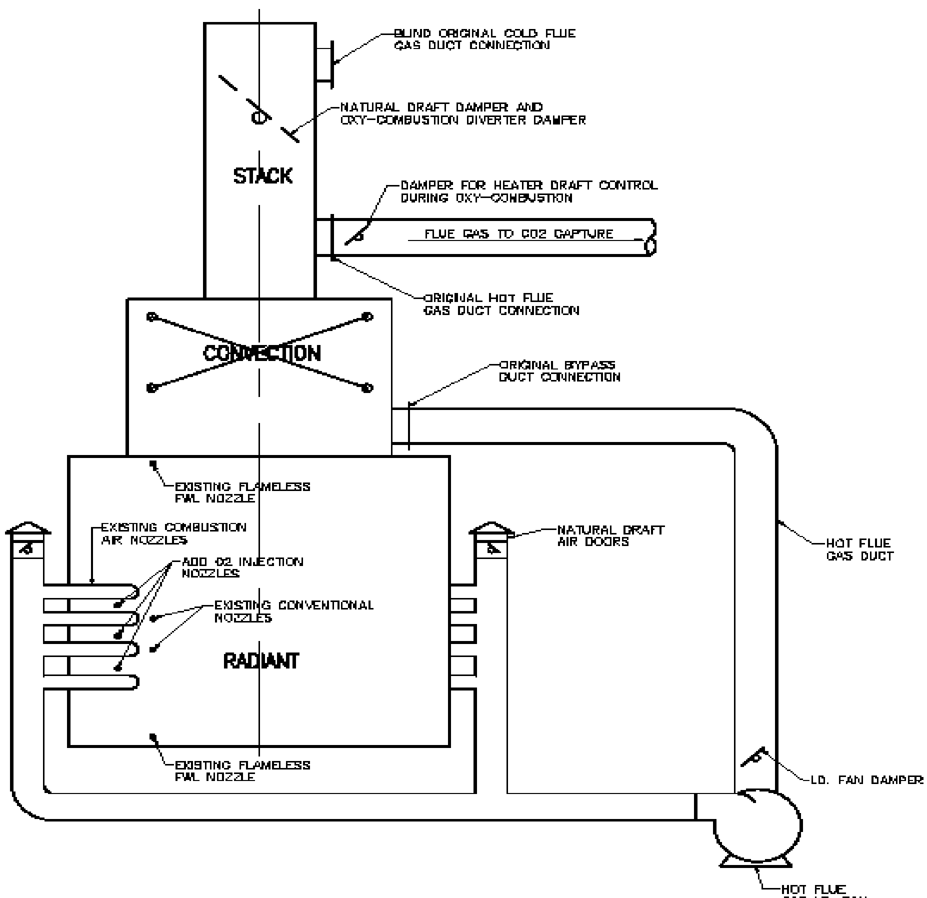

Figure B. 2 - Oxy-Flameless Heater (Reference 17)

Table B. 2 – Predicted Performance of Great Southern Oxy-Flameless Heater

	Traditional Heater	Flameless Heater	Oxy-Flameless Heater
NOx, ppmv	31	4-8	0-1
Excess Oxygen, %	3	3	3
NOx, lb/mmBtu		0.0106	0.0021 or below

ClearSign Technology

ClearSign Combustion Corporation in Seattle has developed two technologies applicable for boilers and heaters: DUPLEX™ technology and Electrodynamic Combustion Control (ECC™). ClearSign expected that these technologies would generate low concentrations of NOx and CO without the need for flue gas recirculation (FGR), SCR or high excess air operation.

DUPLEX™ technology can be installed in new boilers or heaters, or retrofit in existing boilers and heaters. The DUPLEX technology comprises a proprietary DUPLEX tile installed downstream of conventional burners. The hot combustion flame from the conventional burners impinges onto the DULEX tile, and the tile helps radiate heat evenly with high emissivity to the combustion products. DUPLEX operation also creates more mixing and shorter flames. Since the flame length is one parameter that limits the total heat release in a furnace, decreased flame length can allow for significantly higher process throughputs. DUPLEX tile is expected to have a 3- to 5-year life. A demonstration project with San Joaquin Air Pollution Control District and efforts of scaling up the technology to heaters of 5 - 50 million BTU/hr are underway. [20]

The Electrodynamic Combustion Control (ECC™) uses an electric field to effectively shape the flame, accelerate flame speed, and improve flame stability. The total electrical field power required to generate such effects is less than 0.1% of the firing rate.

Bench test performance estimates for DUPLEX and ECC indicated that NOx and CO were less than 5 ppmv, when furnace temperatures were steady maintained between 1200 and 1800 ^{o}F. Beside the benefits of reducing air pollution, ClearSign believes that their burners will provide substantial economic benefits from more uniform heat distribution, improved process throughput, and potentially reduced maintenance costs. [22-23]

Costs and Cost Effectiveness for SCRs

Staff developed a cost curve that plots the PWV of the control devices as a function of boiler/heaters' maximum rating utilizing the following sets of data:

- Refinery Survey Data
- Refinery Consultant's Analysis
- Data provided by three SCR manufacturers, Great Southern Flameless and ClearSign.

The PWVs determined from the cost curve were used to estimate the costs and cost effectiveness for all 212 boilers/heaters at the refineries. The details follow.

Survey Data

As a component of the RECLAIM BARCT evaluation, a survey was submitted to the refineries in 2013 requesting cost information for their boilers and heaters operated with SCRs. There are 14 heaters at the refineries that currently achieve between 1.6 ppmv and 3.5 ppmv NOx at 3% oxygen with the use of SCRs. Table B.3 lists several key characteristics of the heater/SCR combination including: the 2011 emissions, the NOx concentration measured at the stack, the heater maximum rating, and the year of SCR installation, the equipment costs (in the year of installation), installation costs (in the year of installation), and annual operating costs reported by the refineries. [13] A Marshall Index was used to bring the reported costs to the present dollars. Several heaters share a control device. Where this occurs, staff apportioned the reported costs for SCRs into individual SCR costs for each heater based on their relative maximum input ratings. The PWV of individual heaters are estimated using Equation 1 and 2.

$$PWV = (TIC + (15.62 \times AC)) \times \text{Marshall Index} \qquad \text{(Equation 1)}$$

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $. The catalyst replacement costs were reported as a part of the annual operating costs

$$PWV_{\text{Heater A}} = PWV * R_{\text{Heater A}} / R_{\text{All Heaters}} \qquad \text{(Equation 2)}$$

Where:

$PWV_{\text{Heater A}}$ = Present Worth Value of Heater A
$R_{\text{Heater A}}$ = Maximum Rating of Heater A
$R_{\text{All Heaters}}$ = Total Maximum Rating of All Heaters

From the set of all 14 data points above, staff obtained the following ratios:

Installation Costs = 2.807 x Equipment Costs
Total Installed Costs = 3.870 x Equipment Costs
Present Worth Values = 4.072 x Equip Costs = 1.052 x Total Installed Costs (Equation 3).

Table B. 3 – Costs of SCRs Estimated Based on Information Submitted by Refinery

Device	Process	mmBtu/ hr	2011 Emissions (Tons)	Existing NOx ppmv at 3% O2	Shared Control	PWV ($M)
Heater	FCCU	51	13.5	59	Yes	2.56
Heater	FCCU	39	8.24	59	Yes	1.96
Heater	Crude	350	68.6	33	No	6.84
Heater	Crude	154	15.82	20	No	6.02
Heater	Cat Reform	116	10.32	33	Yes	3.89
Heater	Cat Reform	68	7.31	33	Yes	2.83
Heater	Cat Reform	71	5.12	33	No	2.38
Heater	Cat Reform	56	6.09	33	Yes	1.88
Heater	Cat Reform	19	0.8	33	Yes	0.64
Heater	Cat Reform	110	48.64	75	Yes	3.7
Heater	Cat Reform	100	16.17	75	Yes	3.36
Heater	Cat Reform	70	25.73	75	Yes	2.35
Heater	Cat Reform	42	21.16	75	Yes	1.41
Heater	Cat Reform	24	13.1	75	Yes	0.81
Heater	H2 Production	340	70.32	34	No	20.41
Boiler 11	Steam Generation	352	58.99	56	No	15.04
Boiler 8	Steam Generation	179	32.48	85	No	9.99
Boiler 6	Steam Generation	250	61.66	75	No	12.2

Refinery's Consultant Study

A refinery provided information to SCAQMD staff from a study conducted by their consultant. This study estimated actual costs to install SCRs for 18 heaters at the refinery. The heaters have capacity ranging from 39 - 352 mmBtu/hr. Several heaters were to share a common SCR. The estimated PWVs for these 18 heaters were calculated using the refinery consultant's estimates for the total installed costs and a multiplier factor of 1.052 (Equation 3). The PWVs of common SCRs were apportioned as individual SCR costs for individual heaters using the heater maximum ratings. The PWVs for 18 heaters are summarized in Table B.4. [14]

Table B. 4 – Performance and Cost Information of SCRs for Process Heaters from Refinery Survey

Process	mmBtu/hr	2011 Emissions (Tons)	Year of Installation	Existing NOx ppmv (3% O2)	Shared Control	Equipment Cost ($M)	Installation Cost ($M)	Marshall Index	PWV ($M)
Crude	85	0.42	2008	3.5	No	0.76	0.72	1.09	2.87
Hydrotreating	28	1.29	2007	2.7	Yes	0.42	0.18	1.13	0.99
Hydrotreating	22	0.55	2004	2.7	Yes	0.42	0.18	1.13	0.78
Hydrotreating	13	0.42	2007	2.7	Yes	0.42	0.18	1.13	0.45
Coking	176	17.06	1992	2.7	Yes	2.76	6.83	1.64	5.39
Coking	176	17.15	1992	2.7	Yes	2.76	6.83	1.64	5.39
Coking	176	20.79	1992	2.7	Yes	2.76	6.83	1.64	5.39
Cat Reform	177	1.08	1994	1.6	Yes	1.95	5.85	1.56	3.88
Cat Reform	125	0.89	1994	1.6	Yes	1.95	5.85	1.56	2.74
Cat Reform	88	0.53	1994	1.6	Yes	1.95	5.85	1.56	1.93
Cat Reform	199	1.43	1994	1.6	Yes	1.95	5.85	1.56	4.36
H2 Production	653	8.93	2000	2.7	No	7.65	22.95	1.42	44.12
Crude	83	0.86	2001	2.7	No	7.5	22.5	1.42	43.27
Hydrotreating	78	0.27	2003	2.3	No	4.98	14.93	1.38	28.11

Note: Staff used all 14 data points to estimate the ratios of 2.807, 3.870 and 4.072 in Equation 3 however staff did not include data point #13 and #14 on Figure B.3 since the costs of these data points are out of the norm (e.g. data point #13 of $43 million for a 83 mmBtu/hr heaters as compared to data point #12 of $44 million for 653 mmBtu/hr heater.)

SCR Manufacturers

All SCR manufacturers that staff contacted confirmed the following:

- It is feasible to achieve 2 ppmv NOx at 5 ppmv ammonia slip; and
- The costs for SCRs to achieve 2 ppmv NOx is about 10% higher than the costs of SCRs to meet 5 ppmv NOx.

Three SCR manufacturers provided SCR equipment costs. Staff used a multiplication factor of 4 to estimate the PWVs using Equation 3 and the actual reported costs from several refineries submitted in response to the SCAQMD survey.

After refinery visits, a multiplication factor of 4 was used to estimate the TIC (not PWV) as recommended by several refineries to reflect the difficulty of installing SCR for retrofit applications. [15-17] In addition, the following costs were added to the TIC of the SCRs listed in Table B.5:

- Induced draft fans:
  - $1.26 M for 100 mmBtu/hr heater,
  - $1.69 M for 163 mmBtu/hr, and
  - $2.67 M for 350 mmBtu/hr as estimated by NEC [24]
- Ammonia tanks: $1.5 M per NEC recommendation [24]
- CEMS: $100,000 based on data submitted to the SCAQMD in previous CEMS applications.

Great Southern Flameless

Great Southern Flameless provided costs data based on the following assumptions, and the results are summarized in Table B.6 and Table B.7. [20-21]

- 5 ppmv NOx outlet concentration for standard flameless heater
- 3 ppmv NOx outlet for standard flameless heater with pilots off during flameless firing
- 2 ppmv NOx outlet for standard flameless heater with pilots off during flameless firing and fuel conditioning (25% natural gas and 75% fuel gas)
- 1 ppmv NOx outlet concentration for standard oxy-fueled flameless heater
- The equipment costs include burner management system (BMS) control
- Oxygen costs is estimated at $70 per ton for 93% oxygen concentration
- There is no difference in costs between the 2 ppmv and 5 ppmv NOx flameless heaters
- The PWV was estimated based on 4% interest rate and 20-25 years life for heaters
- The PWV for standard flameless includes the savings due to increase in efficiency (83% to 91%) over the conventional heaters
- The PWV for standard oxy-fuel flameless is based on 20% (mass) injection of O2 and includes the savings due to operating efficiency increase (83% to 93.5%)

Table B. 5 - Costs of SCRs Estimated Based on Information from SCR Manufacturers

	Unit Rating (mmBtu/hr)	NOx in (ppmv)	NOx out (ppmv)	Equip Cost ($ M)	PWV ($ M)	NH3 (lb/hr)
A	163	80	2	0.13	0.52 – 3.81 (note 7)	10
	163	80	2	0.10 (NH_3 Slip Cat)	0.4 – 3.99 (note 7)	10
B	100	100	5	0.27 (note 1)	1.08 – 3.94 (note 7)	17
	100	100	2	0.30	1.30 – 4.16 (note 7)	17.5
	350	100	5	0.33 (note 2)	1.30 – 6.0 (note 7)	57
	350	100	2	0.38	1.50 – 6.0(note 7)	59
C	100	100	5	0.20 (note 3)	0.80 – 4.0 (note 7)	5.8
	100	100	2	0.22	0.88 – 4.0 (note 7)	6.0
	350	100	5	0.65 (note 4)	0.26 – 4.53 (note 7)	17.5
	350	100	2	0.70	0.28 – 4.55 (notes 5,7)	17.8

Note: 1) SCR replacement costs were estimated to be $10,000 - $15,000 every 3 – 5 years; 2) SCR replacement costs were estimated to be $20,000 - $25,000 every 3 – 5 years; 3) SCR replacement costs were estimated to be $23,000 - $24,000 every 6 to 7 years ; 4) SCR replacement costs were estimated to be $70,000 - $72,000 every 6 to 7 years; 5) Manufacturer C also estimated annual operating costs based on ammonia costs of about $800 per ton, and using this data, the PWV of the SCR for the 350 mmBtu/hr heater to meet 2 ppmv would be $2,218,040 million which is in the range of $2,800,000 estimated by using the multiplier factor of 4 and the equipment costs provided by the manufacturer. 6) Ammonia slip is 5 ppmv in all categories listed in Table B-6. 7) The high end of the range includes the costs of SCR, induced draft fan, ammonia tank, and new CEMS.

Table B. 6 – Costs for Great Southern Flameless Heaters

Fired Duty HHV (mmBtu.hr)	Equipment Costs ($)	Installation Costs ($)	Total Installed Costs ($)
32	1,909,005	3,818,010	5,727,015
117	3,813,040	7,626,080	11,439,120
187	4,345,000	8,690,000	13,035,000
321	5,332,800	10,665,600	15,998,400

Table B. 7 - Costs for Great Southern Flameless Heaters with Fuel Savings

Fired Duty HHV (mmBtu/hr)	PWV for Flameless Heater 2 ppmv NOx ($ M)	PWV for Oxy-Fuel Flameless 1 ppmv NOx ($ M)
32	4.9	10
117	7.8	22
187	7.0	32
321	5.5	50

ClearSign

ClearSign provided the estimates summarized in Table B.8 for DUPLEX burners to achieve 5 ppmv NOx and also 2 ppmv NOx. Note that their estimates did not yet include the economic benefits for more uniform heat distribution or improved process throughput and potential reduced maintenance costs. ClearSign indicated that their cost estimates were conservative and can be adjusted due to market demand. In addition, ClearSign provided an analysis showing the revenue savings of about $36,000 per ton NOx reduced using DUPLEX burners compared to SCR to achieve the proposed BARCT levels. [23]

Table B. 8 - Costs for DUPLEX Burners

Maximum Input Rating (mmBtu/hr)	PWV for 2 ppmv DUPLEX ($ M)	PWV for 5 ppmv DUPLEX ($ M)
12	0.442	0.102
24	0.884	0.204
48	1.767	0.408
96	3.535	0.815
150	5.523	1.274
200	7.292	1.682
400	14.728	3.397

Present Worth Values and Cost Effectiveness

The aggregated control equipment cost data for the boilers and heaters was sorted into 5 categories based on maximum firing rate and a representative maximum PWV for the control equipment in the category was set. Two sets of costs per firing rate were developed: one set for a 5 ppmv emissions rate and a second group for a 2 ppmv emissions limit.

For 5 ppmv SCR:

$5 M for ≤ 100 mmBtu/hr boilers and heaters
$10 M for > 100 – 200 mmBtu/hr boilers and heaters
$20 M for > 200 – 400 mmBtu/hr boilers and heaters
$30 M for > 400 – 600 mmBtu/hr boilers and heaters
$45 M for > 600 mmBtu/hr boilers and heaters

Per manufacturer's recommendation, the representative PWV cost for each category was multiplied by a factor of 1.1 for the 2 ppmv limit. A cost curve was then constructed relating the PWV for the control devices as a function of boiler/heater maximum rating determined from the five sets of data shown above. Figure B.3 illustrates the linear cost curve and distribution of control equipment by PWV/firing rate. PWVs were estimated for each boiler/heater (from the 212 pieces of equipment in the inventory) using the linear equation.

For 2 ppmv SCR:

$5.5 M for units with maximum rating ≤ 100 mmBtu/hr
$11 M for units with maximum rating > 100 – 200 mmBtu/hr
$22 M for units with maximum rating > 200 – 400 mmBtu/hr
$33 M for units with maximum rating > 400 – 600 mmBtu/hr
49.5 M for units with maximum rating > 600 mmBtu/hr

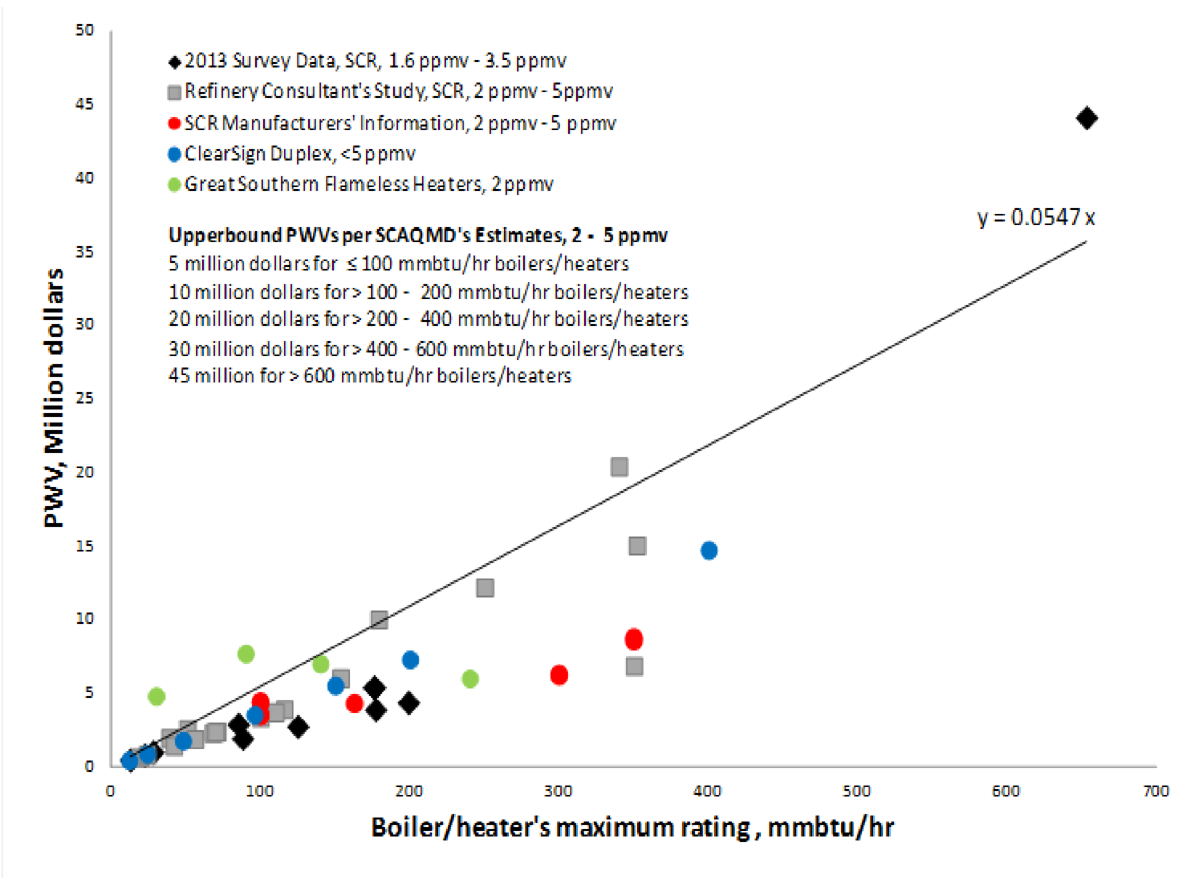

Figure B. 3 – Revised PWVs of Control Devices for Refinery Boilers/Heaters (March 2015)

Incremental Cost Effectiveness was estimated as follows based on the Discounted Cash Flow (DCF) method. A multiplication factor of 1.65 was used to estimate the cost effectiveness using the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

Units with cost effectiveness exceeding $50,000 per ton were excluded from estimating the total emission reductions and the average cost effectiveness for the category of boilers and heaters. Staff estimated there would be 103 units that would be cost effective with total PWVs of $254.5 Million and an average cost effectiveness of $27 K per ton NOx reduced as of December 2014.

Consultant's Analysis for SCRs

NEC concurred that the 2 ppmv BARCT level is feasible for refinery boilers/heaters >40 mmBtu/hr. However, NEC recommended using SCRs with 4 layers of catalysts. NEC stated:

> "NEC feels that 2 ppmv NOx at 3% O_2 and 5 ppmv ammonia slip is an achievable BARCT level. If the refinery heaters and boilers were only burning natural gas, this 2 ppmv NOx level could be achieved by installing three SCR catalyst beds in series. However, to improve the NOx removal efficiency while burning RFG, which is necessary as all of the heaters routinely operate in this mode, NEC recommends the addition of an Ammonia Slip Catalyst (ASC) bed downstream of the third SCR bed to enhance performance. The ASC bed will permit the SCR to operate with higher ammonia loadings when needed and still guarantee the 5 ppmv ammonia slip. An additional complication in controlling the NOx level on refinery heaters is that many of them have duties that change significantly over short periods of time due to process and feed variations. The ASC bed will also alleviate this difficulty."[24]

NEC estimated their cost profile based on data provided by a manufacturer for a FCCU's SCR, upgrading the base cost for a 2-catalyst layer SCR to a 4-catalyst layer model. As with the FCCU example, the manufacturer's cost proposal was adjusted by a 1.35 factor for bid conditioning followed by a 1.75 factor for labor and a 4.5 factor to estimate the total installed cost. The NEC 4-catalyst layer model added the costs of an induced draft fan, CEMS and an ammonia injection system to their prototype SCR. The resulting profile was sized for a series of heating rates to establish cost curve that related PWV to mmBtu. Their cost equation was applied to the same boiler heater data set to estimate the cost effectiveness of achieving a 2 ppmv emissions rate.

The difference between the staff and NEC cost estimates are greatest for the units less than 200 mmBtu/hr where the staff estimate is roughly half of the NEC estimate (e.g., for 125 mmBtu/hr, staff: $11 million and NEC: $18 million). For heating values approximately 300 mmBtu/hr and higher the costs estimate converge (e.g., for 525 mmBtu/hr, staff: $33 million and NEC: $32.7 million). The impact of applying the NEC algorithm resulted in higher costs for the units with lower firing rates and as a result only 48 heaters/boilers became cost-effective. A comparison between NEC and staff's results are tabulated in Table B.9.

Table B. 9 - Comparison of NEC's and Staff's Cost Estimates for SCRs (December 2014)

	Staff's Estimates	**Staff's Estimates with NEC's Cost Information**
Total Boilers and Heaters	212	212
Number of Cost-Effective Units	103	48
Total PWVs for Cost-Effective Units	$254.5 M	$162 M
Total Emission Reductions	1.05 tpd	0.61 tpd
Average Cost Effectiveness	$27 K per ton DCF	$29 K per ton DCF

It is important to acknowledge that the two approaches were similar in relating firing rate to PWV to estimate cost effective SCR applications. However the underlying the costs, including the sizing of the SCR catalyst layer configuration (1 to 4 layers) were distinctly different. Both assumptions yield estimates to achieve a 2 ppmv emissions target. The average cost effectiveness is essentially the same and less than the $30,800 thresholds established for SCR control equipment established for boilers greater than 75 mmBtu/hr in SCAQMD Rule 1146. The difference in total emissions reduced by the two methodologies is 0.44 TPD.

Upon review of NEC's analysis, staff agreed with the following recommendations from the refineries and revised its cost analysis accordingly:

1. The refineries requested staff to use a factor of 4 (not of 3, which was a combination of the 1.86 factor recommended in the EPA OAQPS Guidelines and 50% added contingency) to estimate the installed costs from the equipment costs provided by the manufacturers. Staff agreed with this recommendation and revised the calculated PWVs based on the manufacturers' information. Revised PWVs are included in Figure B.3 above.

2. For heaters <110 mmBtu/hr with existing SCRs, the refineries requested staff to consider the full costs of SCR installations, not the "incremental" costs in estimating the cost effectiveness values. Staff concurred with this request.

Staff's revised costs and cost effectiveness estimate are summarized in Table B.10. Table B.11 provides the details of the application of the revised methodology to the affected boilers and heaters. The revised analysis results in slightly lower incremental emission reductions and a nominal increase in cost. This revision modified the difference in total NOx emissions reduced by the staff and NEC methodologies to a new total of is 0.33 TPD. Note that an adjustment is proposed to reduce the overall NOx RECLAIM shave amount to account for uncertainties in the BARCT analysis related to these different methodologies. The proposed adjustment is significantly larger than 0.33 TPD.

Table B. 10 – Revised Cost Estimates of SCRs for Boilers and Heaters

Total Boilers and Heaters	212
No of Cost-Effective Units (<50,000 $/ton)	82
No of SCRs	75 (24 upgraded, 51 new)
Total PWVs for Cost-Effective Units	237
Total Emission Reductions	0.94 ton per day
Average Cost Effectiveness	28 K $/ton DCF, 45 K $/ton LCF

Staff's Recommendation

Staff proposes to set a new BARCT level of 2 ppmv NOx for refinery boilers/heaters >40 mmBtu/hr because NOx control technologies such as SCR, LoTOx, Great Southern Flameless heaters are either commercially available, achieved-in-practice and/or can be designed to achieve 2 ppmv NOx in a cost-effective manner.

Incremental Emission Reductions beyond 2005 BARCT level: 0.94 tons per day
Total Incremental Costs: $ 237 M
Average Incremental Cost Effectiveness: $28 K/ton (DCF) and $45 K/ton LCF)

Table B. 11 – Details of Cost Estimates for Boilers and Heaters

Summary of CE for Boilers/Heaters

Results:

Total units = 23 boilers + 189 heaters = 212 units

Cost-effective units = 82. Not cost-effective units = 130
Total SCRs = 75 (24 upgraded, 51 new)

Total PWVs = 237 millions. Total emission reductions = 0.94 tpd.

Average cost effectiveness = 27,710 $/ton DCF = 45 K $/ton LCF

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
1	6	925	HEATER	H2 PRODUCTION	931	0.06	0.03	49.50	45.00	4.50	19,066	SCR 87	5.65
2	5	3530	HEATER	H2 PRODUCTION	653	0.02	0.02	49.50	45.00	4.50	30,425	SCR 00	2.69
3	1	570	HEATER	H2 PRODUCTION	650	0.10	0.02	49.50	45.00	4.50	20,782	SCR 85, LNB 6	12.66
4	1	27	HEATER	CRUDE	550	0.13	0.02	33.00	30.00	3.00	17,671	LNB 97	21.18
5	6	913	HEATER	CRUDE	457	0.09	0.01	33.00	30.00	3.00	21,995	SCR 92	13.68
6	1	1465	HEATER	H2 PRODUCTION	427	0.03	0.01	33.00	30.00	3.00	24,476	SCR, LNB 95	7.25
7	5	641	HEATER	HYDROCRACKING	365	0.18	0.02	22.00	20.00	2.00	13,703	LNB 99	27.69
8	8	429	BOILER	STEAM GEN/SCR09	352	0.03	0.01	22.00	20.00	2.00	25,992	SCR 2009	6.00
9	8	430	BOILER 11	STEAM GEN	352	0.16	0.01	22.00	20.00	2.00	27,891		
10	8	59	HEATER	CRUDE	350	0.19	0.01	22.00	20.00	2.00	16,363		
11	7	220	HEATER	H2 PRODUCTION	350	0.08	0.01	22.00	20.00	2.00	22,064	SCR 1990	21.66
12	5	2216	BOILER	STEAM GEN	342	0.11	0.01	22.00	20.00	2.00	22,257	SCR 88	47.16
13	6	1236	BOILER	STEAM GEN	340	0.01	0.01	22.00	20.00	2.00	23,944	SCR 97	6.76
14	8	210	HEATER	H2 PRODUCTION	340	0.19	0.01	22.00	20.00	2.00	25,457		
15	6	1239	BOILER	STEAM GEN	340	0.02	0.01	22.00	20.00	2.00	27,239	SCR 97	7.75
16	5	82	HEATER	CRUDE	315	0.02	0.01	22.00	20.00	2.00	18,018	SCR 91	5.69
17	5	83	HEATER	CRUDE	315	0.02	0.01	22.00	20.00	2.00	19,885	SCR 91	5.69
18	1	535	HEATER	CAT REFORM	310	0.07	0.01	22.00	20.00	2.00	27,440	LNB 94	22.84
19	6	803	BOILER	STEAM GEN	309	0.21	0.01	22.00	20.00	2.00	41,496	LNB 86	104.00
20	7	686	BOILER 7	STEAM GEN	304	0.02	0.01	22.00	20.00	2.00	31,442	SCR 2009	8.50
21	1	63	HEATER	CRUDE	300	0.01	0.01	22.00	20.00	2.00	24,097	SCR, LNB 94	4.81
22	6	805	BOILER	STEAM GEN	291	0.19	0.01	22.00	20.00	2.00	42,085	LNB 88	74.91
23	1	532	HEATER	CAT REFORM	255	0.04	0.01	22.00	20.00	2.00	34,138	LNB 01	16.64
24	7	688	BOILER 6	STEAM GEN	250	0.17	0.01	22.00	20.00	2.00	42,403		
25	9	1550	BOILER/ne w SCR	STEAM GEN	245	0.02	0.01	22.00	20.00	2.00	26,507	SCR 2008	5.39
26	5	643	HEATER	HYDROCRACKING	220	0.04	0.01	22.00	20.00	2.00	31,409	LNB 99	19.63
27	5	84	HEATER	CRUDE	219	0.02	0.01	22.00	20.00	2.00	23,986	SCR 91	5.69
28	5	20	HEATER	CRUDE	217	0.06	0.01	22.00	20.00	2.00	31,482	LNB 01	23.16
29	9	430	HEATER	HYDROTREATING	200	0.02	0.01	11.00	10.00	1.00	12,602	SCR	8.43
30	4	9	HEATER	CRUDE	199	0.10	0.01	11.00	10.00	1.00	14,133	SCR	31.91 - 41.32
31	5	3031	HEATER	CAT REFORM	199	0.00	0.01	0.00	0.00	0.00	0	SCR 94	1.64

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
32	7	687	BOILER 8	STEAM GEN	179	0.09	0.00	11.00	10.00	1.00	25,410		
33	5	471	HEATER	CAT REFORM	177	0.00	0.00	0.00	0.00	0.00	0	SCR 94	1.64
34	5	161	HEATER	COKING	176	0.06	0.01	11.00	10.00	1.00	18,504	SCR 92	2.71
35	5	159	HEATER	COKING	176	0.05	0.01	11.00	10.00	1.00	18,504	SCR 92	2.71
36	5	160	HEATER	COKING	176	0.05	0.01	11.00	10.00	1.00	20,355	SCR 92	2.71
37	8	104	HEATER	COKING	175	0.05	0.00	11.00	10.00	1.00	22,645		
38	8	105	HEATER	COKING	175	0.05	0.00	11.00	10.00	1.00	24,004		
39	6	914	HEATER	CRUDE	161	0.04	0.01	11.00	10.00	1.00	17,704	SCR 92	13.70
40	8	78	HEATER	CRUDE	154	0.04	0.01	11.00	10.00	1.00	21,401		
41	8	79	HEATER	CRUDE	154	0.04	0.00	11.00	10.00	1.00	23,180		
42	1	29	HEATER	CRUDE	150	0.05	0.00	11.00	10.00	1.00	26,662	LNB 94	35.74
43	4	388	HEATER	HYDROCRACKING	147	0.12	0.01	11.00	10.00	1.00	20,879	SCR	49.6 - 73.5
44	4	1122	BOILER	H2 PRODUCTION	140	0.01	0.00	11.00	10.00	1.00	26,106	SCR	7.7 - 8.1
45	9	6	HEATER	CRUDE	136	0.04	0.01	11.00	10.00	1.00	21,766		19.31
46	7	264	HEATER	HYDROCRACKING	135	0.05	0.00	11.00	10.00	1.00	35,517		
47	1	155	HEATER	COKING	130	0.05	0.00	11.00	10.00	1.00	33,211	LNB 00	39.55
48	1	31	HEATER	CRUDE	130	0.04	0.00	11.00	10.00	1.00	35,015	LEA 01	29.21
49	1	153	HEATER	COKING	130	0.04	0.00	11.00	10.00	1.00	36,700	LNB 97	36.14
50	1	151	HEATER	COKING	130	0.04	0.00	11.00	10.00	1.00	37,286	LNB 97	39.39
51	6	930	HEATER	HYDROCRACKING	129	0.06	0.00	11.00	10.00	1.00	36,151	ULNB 95	55.12
52	9	378	BOILER	STEAM GEN	128	0.01	0.01	11.00	10.00	1.00	20,725	SCR	5.17
53	6	120	HEATER	COKING	126	0.05	0.00	11.00	10.00	1.00	38,824	LNB 95	51.79
54	5	472	HEATER	CAT REFORM	125	0.00	0.00	0.00	0.00	0.00	0	SCR 94	1.64
55	1	67	HEATER	CRUDE	120	0.04	0.01	11.00	10.00	1.00	20,294	LNB 94	34.37
56	4	90	HEATER	FCCU	127	0.06	0.00	11.00	10.00	1.00	44,113	LNB	46.6 - 52.1
57	3	77	BOILER	STEAM GEN	112	0.05	0.00	11.00	10.00	1.00	44,197		
58	3	76	BOILER	STEAM GEN	112	0.05	0.00	11.00	10.00	1.00	44,197		
1	9	768	HEATER	HYDROTREATING	110	0.02	0.04	11.00			31,494	SCR	9.43
2	7	154	HEATER	CAT REFORM	110	0.13	0.03	11.00			41,628		
3	5	451	HEATER	HYDROTREATING	102	0.10	0.03	11.00			40,338	no control	99.31
4	1	33	HEATER	CRUDE	100	0.02	0.02	5.50			25,116	LNB 94	22.79
5	7	155	HEATER	CAT REFORM	100	0.04	0.01	5.50			47,328		
6	9	22	HEATER	COKING	95	0.02	0.02	5.50			29,430		20.33
7	4	89	HEATER	FCCU	95	0.05	0.08	5.50			7,718	LNB	46.6 - 52.1
8	6	269	HEATER	HYDROTREATING	94	0.03	0.01	5.50			44,210	LNB 88	34.10
9	6	918	HEATER	COKING	91	0.08	0.02	5.50			34,411	LNB 91	91.70
10	6	917	HEATER	COKING	91	0.07	0.02	5.50			38,067	LNB 98	82.07
11	1	250	HEATER	FCCU	89	0.02	0.02	5.50			32,240	LNB 95	27.87
12	5	473	HEATER	CAT REFORM	88	0.00	0.02	0.00			0	SCR 94	1.64

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
13	7	146	HEATER	HYDROTREATING	76	0.02	0.01	5.50			43,097		
14	6	85	HEATER	COKING	74	0.06	0.01	5.50			45,265	LNB 88	97.00
15	8	174	HEATER	HYDROTREATING	70	0.06	0.02	5.50			35,422		
16	9	53	HEATER	HYDROTREATING	68	0.01	0.02	5.50			32,565		16.43
17	6	84	HEATER	COKING	67	0.04	0.01	5.50			44,780	LNB 85	116.81
18	6	83	HEATER	COKING	67	0.05	0.01	5.50			45,124	LNB 88	103.95
19	4	770	HEATER	HYDROTREATING	63	0.00	0.02	5.50			32,156	SCR	5.5 - 6.4
20	5	625	HEATER	HYDROCRACKING	63	0.06	0.01	5.50			47,614	no control	90.40
21	7	194	HEATER	HYDROTREATING	60	0.05	0.02	5.50			39,909		
22	4	218	HEATER	CAT REFORM	60	0.02	0.01	5.50			40,392	LNB	29.8 - 32.2
23	5	619	HEATER	HYDROCRACKING	57	0.05	0.01	5.50			45,968	no control	95.47
24	5	617	HEATER	HYDROCRACKING	57	0.05	0.01	5.50			40,839	no control	84.24

Summary

	tpd		
>110	0.44		93.50
40-110	0.495	143.00	
Total Units	0.94		
Total costs		237	
Average CE	27,710		

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23. Costs Information from ClearSign. E-mails from Roberto Ruiz to Minh Pham. July 24-29, 2014.

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Appendix C – Refinery Gas Turbines

Process Description

Gas turbines are used in refineries to produce both electricity and steam. Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40% and combined-cycle efficiencies of 60%. Aero-derivative gas turbines are adapted from aircraft engines. These turbines are lightweight and more efficient than frame turbines however the largest units are available for up to only 40-50 MW. The existing gas turbines at the refineries in the SCAQMD range from 7 MW to 83 MW. Most are all operated with duct burners, heat recovery steam generator (HRSG), Selective Catalytic Reduction (SCR), CO catalysts and some units have Ammonia Slip Catalysts (ASC), Cheng Low NOx (CLN), and Dry Low NOx (DLN) or Dry Low Emissions (DLE) combustors. Figure C.1 shows a typical layout of a turbine, duct burner, HRSG, and control system.

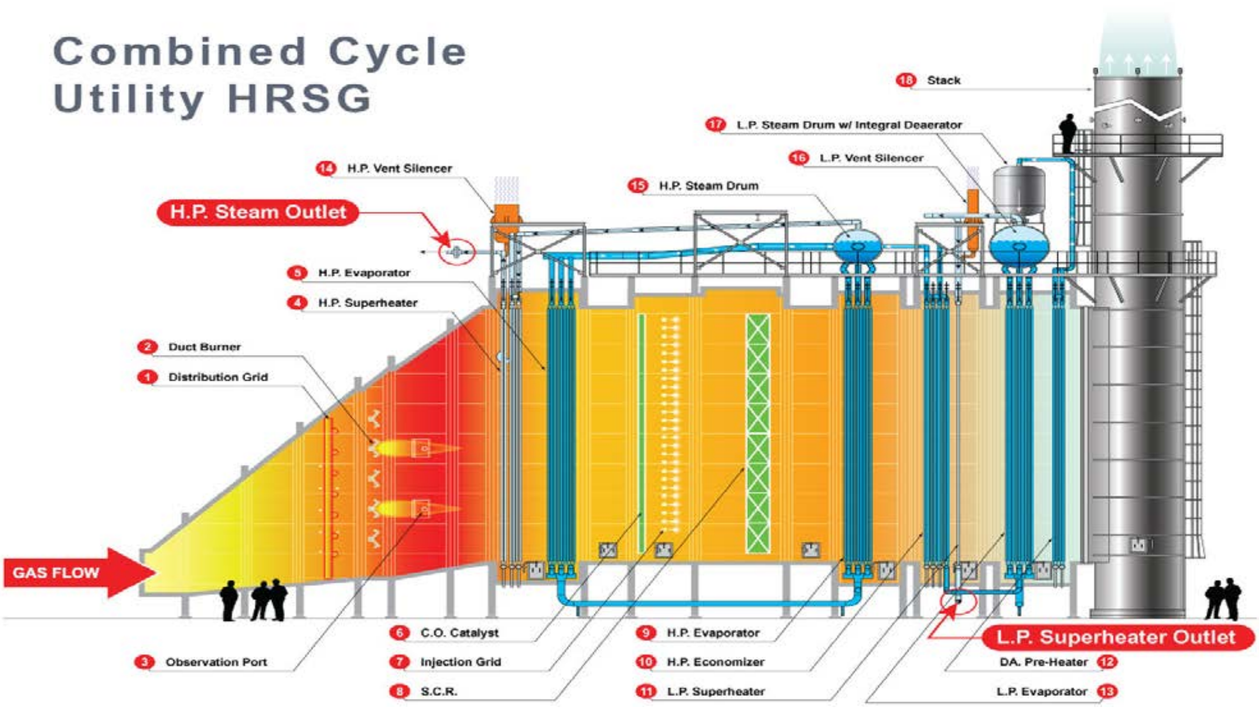

Figure C. 1 - Gas Turbine with Duct Burner (victoryenergy.com)

Emission Inventory

There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tons per day in 2011 as shown in Table C.1. Table C.1 also includes information on the type and size of equipment, what controls are in place, and the year the controls were installed. NOx levels at the stack vary from 1.67 ppmv at 15% O2 for units with SCR and ASC to 5.95 ppmv for units with SCR and water injection. [1]

It should be noted that at the inception of the RECLAIM program, the SCAQMD staff provided allocations for the gas turbines based on the 2000 BARCT level of 62.27 lbs/mmscft. If all gas turbines/duct burners were operated at the 2000 BARCT level of 62.27 lb/mmscft, the emissions from these turbines would amount to about 4.86 tons per day. In addition, these units are subject to either BACT limits or permit conditions that limit the annual mass emissions at the time the permits were issued: Refinery 1's gas turbines/duct burners have a BACT limit of 8 ppmv NOx; Refinery 5, 6 and 7's units have a BACT limit of 9 ppmv; and units at Refinery 4 are subject to a limit of 583 tons per year of NOx emissions. If these gas turbines/duct burners were operated at the BACT levels or at the levels specified in the permit conditions at the time the permits were issued, the emissions would be 5.99 tons per day, higher than 4.86 tons per day of the 2000 BARCT. All of the gas turbines are currently emitting at a level below their allocations and below the levels at the time their permits were issued. Technology improvements with time and the implementation of BACT levels have recently changed emissions to 2 ppmv for frame turbines and 2.5 ppmv for aero-derivative units.

Achieved-In-Practice NOx Levels for Gas Turbines

- Refinery 10's 7 MW aero-derivative gas turbine/duct burner with Cormetech SCR and ASC operating under a permit condition of 2.5 ppmv NOx, 15% O_2 has actually achieved the levels below 2 ppmv NOx at 15% O_2. [1, 6, 9, 25]

- In 2010, Refinery 5 received a permit to construct a new 46 MW frame gas turbine/duct burner with DLN, SCR and CO catalysts. The permit has a limit of 2 ppmv NOx, 15% O_2 and 5 ppmv NH3 slip. This unit has been in operation since 2012. [28-29]

- In 2011, Refinery 1 received a permit to construct for ~~a~~an 85 MW gas turbine /duct burner with DLN, SCR and CO catalyst. The permit condition required the turbine to be operated at a BACT level of 2 ppmv NOx, 15% O2. Regardless of the permit, Refinery 1 did not install the gas turbine. [7]

The above 7 MW aero-derivative, 46 MW and 85 MW frame gas turbines/duct burners demonstrate the feasibility of the proposed level of 2 ppmv NOx, 15% O2, annual average, for gas turbines using natural gas as well as refinery gas. The limits stated in the permit conditions are based on short-term averages (e.g. 1-hour average), which is more stringent than the proposed BARCT at 2 ppmv, annual average.

Table C. 1 - 2011 Emissions for Refinery Gas Turbines/Duct Burners

Fac ID	Device ID	Device	mmBtu/hr	MW	Turbine Type	2011 Emissions (lbs)	Control & Year	Existing ppmv NOx at 15% O2
1	1226	Turbine	986	83	GE	78,418	DLE, SCR, CO, 88	2.80
1	1227	Duct Burner	340			27,097	SCR, CO, 88	2.80
1	1233	Turbine	986	83	GE	69,996	SCR, CO 98	3.50
1	1234	Duct Burner	340			22,034	SCR, CO 98	3.50
1	1236	Turbine	986	83	GE	72,933	SCR, CO, 88	2.53
1	1237	Duct Burner	340			21,090	SCR, CO, 88	2.53
1	1239	Turbine	986	83	GE	85,228	SCR, CO, 88	2.52
1	1240	Duct Burner	340			15,262	SCR, CO, 88	2.52
6	926	Turbine	316	23	GE	110,546	SCR, 87	5.65
4	810	Turbine	392	30	Pratt Whitney	55,264	SCR, CO, WI	5.95
4	812	Turbine	392	30	Pratt Whitney	50,084	SCR, CO, WI	4.82
7	828	Turbine	646	59	Westinghouse	118,842	SCR, 86	5.65
7	829	Duct Burner	99			16,191	SCR, 86	5.65
5	2198	Turbine A	560	46	GE Frame6	73,759	SCR, 95	4.20
5	2199	Duct Burner	120			7,521	SCR, 95	4.20
5	2207	Turbine B	560	46	GE Frame6	61,809	SCR, 95	3.46
5	2208	Duct Burner	120			9,569	SCR, 95	3.46
5	3053	Turbine C	506	46	GE Frame6	68,408	SCR, 96	4.24
5	3054	Duct Burner	286			5,686	SCR, 96	4.24
10	677	Turbine	90	7	Solar, Taurus	1,598	SCR, ASC, 03	1.67
10	679	Duct Burner	50		Solar, Taurus	430	SCR, ASC, 03	1.67
					Total (tpd)	**1.33**		

Control Technology

Gas turbines/duct burners are capable of emitting very low NOx emission levels. Currently most of the units at the refineries in SCAQMD are emitting less than 5 ppmv NOx using commercially available control technologies such as water or steam injection, DLN, DLE, CLN, SCR, CO catalysts and ASC.

Water or Steam Injection

Most of the NOx generated in the gas turbine/duct burner is "thermal" NOx. Water or steam injected into the high temperature frame zone quench the temperature down and reduce NOx to approximately 25 ppmv at 15% O2. However, water/steam injection tends to increase the CO emissions appreciably.

Dry Low NOx (DLN) and Dry Low Emissions (DLE)

DLN/DLE is based on a concept of lean premixed combustion – gaseous fuel is premixed with combustion air at the air to fuel ratio two times higher than the stoichiometric ratio. The lean mixture reduces peak flame temperature in the combustion zone and suppresses "thermal" NOx formation. The premixing chamber for the combustion air and gaseous fuel must be specifically designed for each type of turbines and integrated into the turbine design. Every 4 to 5 years, the combustion liners of the DLE/DLN combustors are deteriorated and must be replaced. Table C.2 shows potential performance of DLN/DLE in certain models of GE frame and aero-derivative turbines. A few models of natural-gas-fired turbines can reach as low as 3-5 ppmv NOx. Maintaining the low NOx emission levels from the turbines from full to low load, or from turbines with varying load swings coupled with the emissions from the duct burners remain a challenge for DLN/DLE combustor technology. Most manufacturers would guarantee a level of 15-25 ppmv for DLE/DLN combustors. [14-16]

Table C. 2 – Performance of DLN and DLE

Combustion System	Frame Type	Potential NOx Level
DLN1	GE 3/5/6B/7/9E	9-25 ppmv
DLN1	GE 6B/7E/9E	3-5 ppmv
DLN2.6	GE 6F/7F	9 ppmv
DLN2.6	GE 9F	9 ppmv
Combustion System	**Aero-derivative Type**	**Potential NOx Level**
DLE	GE LMS100 (100 MW)	25 ppmv (gaseous fuel)
DLE	GE LM6000 (40-55 MW)	15-25 ppmv (gaseous fuel) 100 ppmv (liquid fuel)
DLE	GE LM2500 (28 – 34MW)	15-25 ppmv (gaseous fuel) 100 ppmv (liquid fuel)

Cheng Low NOx (CLN)

Cheng Low NOx is an alternative to DLN/DLE. [17-23] In lieu of premixing air to fuel, CLN premixes steam with fuel prior to combustion. The difference in the CLN and the traditional steam injection technology is that CLN can deliver a uniform homogenous mix of steam and fuel to the combustion chamber. A schematic diagram for the CLN is shown in Figure C.2.

The effect of homogeneity on CO and NOx emissions is shown in Figure C.3. With careful mixing, the steam to fuel ratio can be extended to 4 to 1 without causing any flameout and increasing CO emissions. The NOx level can theoretically be lowered to 1 ppmv without the use of SCR. The CO level can be reduced to below 2 ppmv without the use of CO catalyst. [17-20]

The CLN technology was developed by Cheng Power Systems, Inc. It was patented in 2002. Since 2005, the CLN technology has been running continuously on a 6 MW Allison Rolls Royce (RR) KB5S at the Stanford Research Institute (SRI) in Menlo Park. In 2009, it was demonstrated on a GE LM2500 at Calpine Corporation's Agnews Cogeneration Plant. The newest CLN was installed in the GE LM2500PH gas turbine. Table C.3 below shows a list of CLN installations in the past decade.

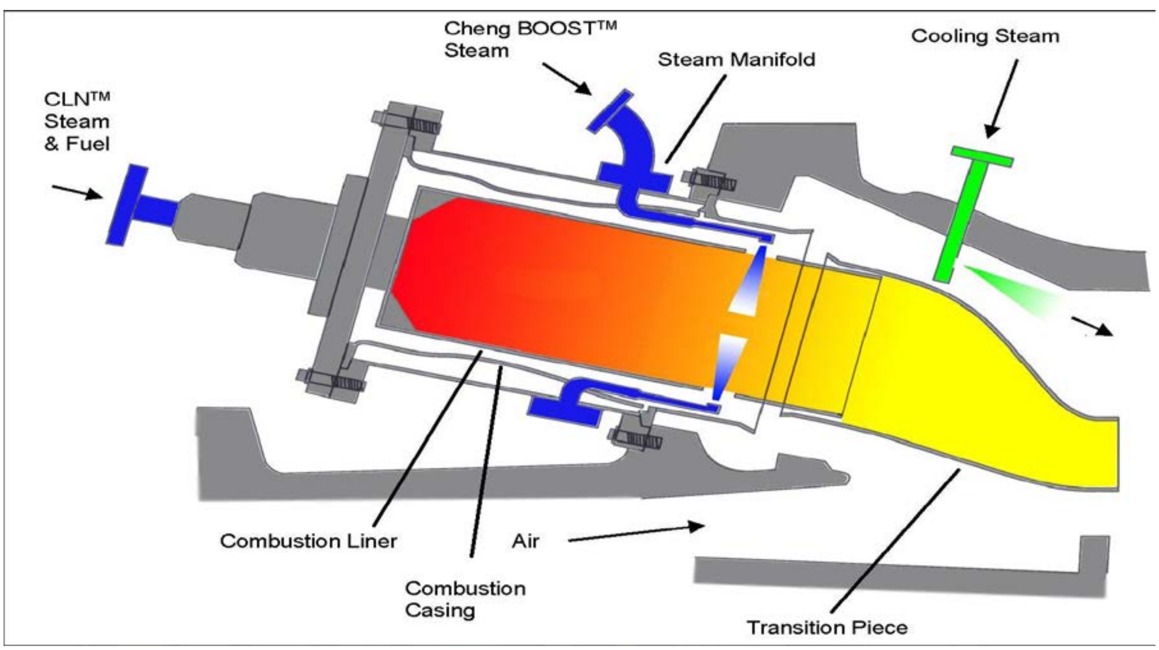

Figure C. 2 - Cheng Low NOx (Reference 22)

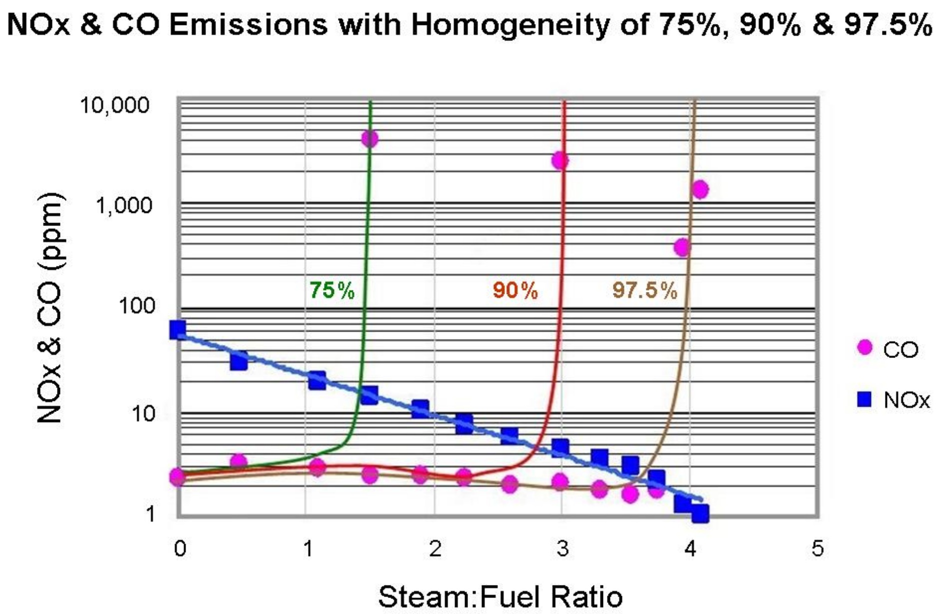

Figure C. 3 - Effect of Homogeneity and Steam to Fuel Ratio in CLN Application (Reference 22)

Table C. 3 – Installations of CLN

Engine	Rated Power, MW
RR 501 KH	6.2
RR 501 KB7S	5.2
RR 501 KB5	3.9
RR Avon 1535	15
GE LM2500	22
GE 6B	39.5
LM 6000 PC	43
GE 7EA	85

Figure C.4 below shows some of the test results of CLN. Additional test results can be found in References 18-20. It should be noted that, CLN was put in operation on two GE Frame 6B turbines at a refinery in the SCAQMD. Actual test data at the refinery site in the SCAQMD shows a level of 17.7 ppmv NOx at 15% O2 at the steam to fuel ratio of 1.5. [18-19] In addition to lowering NOx and CO emissions, additional benefits that CLN provide are lowering the heat rate and increasing power output.

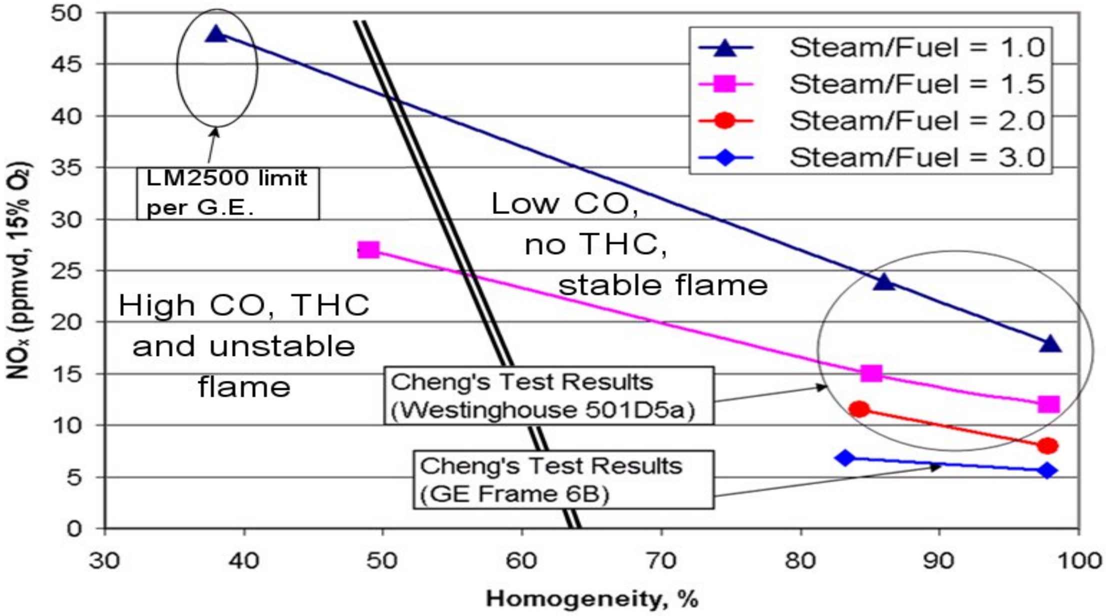

Figure C. 4 - Effect of Homogeneity and Steam to Fuel Ratio on NOx Emissions in CLN Application

In summary, CLN with a steam to fuel ratio of 1.75 to 1 is proven viable to reduce NOx emissions to 9 ppmv or 15 ppmv. SCR can be used in combination with CLN to reach 2 ppmv NOx and CO levels. The current CLN system comes with automatic adjustment software to continuously monitor and optimize the amount of steam to fuel ratio. Cheng Power projects that with a steam to fuel ratio of 3 or 4 to 1, CLN would be able to reach 2 ppmv NOx without the use of SCR.[21-23]

Selective Catalytic Reduction

SCR is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen. Please refer to Appendix A for further descriptions.

All SCR manufacturers that staff contacted confirm that SCRs can be designed to reduce 95%-98% NOx emissions when used in combination with DLE/DLN, CLN, CO catalysts, ASC, or water/steam injection. Two ppmv NOx can be achieved while maintaining low ammonia slips of less than 5 ppmv.

Cormetech indicated that they have achieved less than 2 ppmv NOx and 2 ppmv NH_3 in 10 gas turbines. In addition one of the full scale demonstration projects is a 7 MW cogeneration unit located at a refinery in the Los Angeles Basin (startup in 2003) that achieved <2 ppmv NOx at <0.1 ppmv ammonia slip. [25] BASF advertised that their vanadia/titania catalysts have 99% NOx removal efficiency in the optimum temperature range of 550 – 800 degrees F, and their zeolite catalysts have 99% removal efficiency in the optimum temperature range of 675 - 1075 degrees F, and they also supply ASC that can reduce both ammonia and NOx. [27]

The CO catalysts are used in conjunction with SCR catalysts to concurrently reduce NOx to nitrogen and oxidize CO and hydrocarbon to CO2 and water. The CO catalysts are typically made of platinum, palladium or rhodium, and have about 90% removal efficiency for CO and remove 85% to 90% of hydrocarbon or hazardous air pollutants.

Costs and Cost Effectiveness

It has been reported that the costs of SCR catalysts have dropped significantly over time – catalyst innovations have been the principle driver, resulting in a 20 percent reduction in catalyst volume and costs with no change in performance. [10] Staff developed a cost curve that plots the PWV of the control devices as a function of gas turbines' maximum rating utilizing the following sets of data:

- Refinery data
- EPA and DOE data
- Data provided by SCR manufacturers and Cheng Low NOx

Staff then used the PWVs from the cost curve to estimate the cost and cost effectiveness for all 21 turbines/duct burners at the refineries. The details are explained below.

Refinery 1's Cost Information for SCR

In 2011, Refinery 1 received a permit to construct for an 85 MW gas turbine/duct burner. It was planned as the fifth cogeneration unit at this site. SCR and CO catalysts were proposed to control NOx and CO emissions from a DLN combustor. The total installed costs for SCR and CO provided in their application for permit was estimated to be \$5.9 million. Staff used a Marshall Index factor of 1.2 to adjust to current dollars. [7]

This refinery has four existing cogeneration units at the site emitting between 2.52 ppmv to 3.50 ppmv NOx. The refinery reported through a survey conducted in 2013 that the annual operating costs were \$375,000 per year, and catalyst replacement costs were \$950,000 every 10 years. [8]

Using Equation 1 below with a Marshall Index adjustment factor of 1.2 to bring the costs to present dollars, staff estimated the PWV for the SCR/CO catalysts were approximately \$15.50 million.

PWV = Adjustment Factor x (TIC + (15.62 x AC) + (1.14 x CR)) (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
CR = Catalyst Replacement Costs, $

Refinery 10's Cost Information for SCR

This refinery has a 7 MW cogeneration unit that is using SCR and ASC (installed in 2002) to achieve a level of 1.67 ppmv NOx at 15% O2. The refinery reported total installed costs, annual operating costs, and catalyst replacement costs every 10 years. Using Equation 1 with Marshall Index of 1.4, staff estimated the PWV for SCR/ASC catalysts of approximately $3.8 million. [6, 9]

Costs Information from SCR Manufacturers

All SCR manufacturers that staff contacted confirmed that it is feasible to achieve 2 ppmv NOx at 5 ppmv ammonia slip for natural gas as well as refinery gas applications using SCRs, or combinations of SCRs with CO, or ammonia slip catalysts.

Manufacturer B provided the cost to add catalyst and increase the ammonia usage to the SCR of Refinery 1 to achieve 2 ppmv NOx. In this conservative estimate, Manufacturer B assumed that the existing NOx levels were at 10 ppmv. Manufacturer B believed that with the current SCR system at Refinery 1, the refinery could meet 2 ppmv NOx just by adding ammonia. [5]

Additional catalysts = $234,000 ($250 per cubic foot)
Additional ammonia = $11,000 based on $900 per ton ammonia

Manufacturer A provided several sets of cost information for 1) conventional SCRs and for 2) an advanced SCR with ASC for 83 MW and 7 MW cogeneration units with inlet NOx concentrations at 35 ppmv and 50 ppmv to get to 2 ppmv and 5 ppmv outlet NOx concentrations. The costs are summarized in Table C.4 below: [4]

Table C. 4 – Costs of SCR and ASC for 83 MW and 7 MW Cogeneration Units

Engine	Rated Power 83 MW	Rated Power 83 MW	Rated Power 83 MW	Rated Power 7 MW
Exhaust Flow, lb/hr	2,653,000	2,653,000	2,653,000	140,000
Exhaust Temp, ºF	625	625	625	625
SCR + CO Catalysts				
NOx in, ppmv	35	50	35	50
NOx out, ppmv	2	2	8 (note)	2
CO Conversion, %	67	67	67	90
NH3 Slip, ppmv	5	5	5	5
Costs, $	1,333,000	1,380,000	1,050,000	$75,000
SCR + Ammonia Slip Catalysts				
NOx in, ppmv	35	50	35	50
NOx out, ppmv	2	2	8	2
CO Conversion, %	92	92	67	92
NH3 Slip, ppmv	5	5	5	5
Costs	$986,000	$1,100,000	$650,000	$60,000

Note: 8 ppmv NOx is the existing permit condition of Refinery 1's cogeneration unit.

The SCR, CO and ASC have a catalyst replacement frequency of 10 years. Manufacturer B assumed that the existing ammonia storage tanks and injection systems can be used. Associated equipment such as pumps, control valves and vaporizer capacity may increase costs however, this equipment was not included in the cost estimate. Installation and duct modifications were also not included in the cost estimate. Staff used a multiplier factor of 1.6 to add the costs of modifications and installation based on Refinery 10 data. Assuming the entire existing SCR and CO catalysts were replaced with SCR and ASC using the costs provided by Manufacturer B, staff estimated the SCR/ASC's PWVs would be approximately of $19 million for the 83 MW turbine and $2 million for the 7 MW turbine.

SCR Cost Information in Literature

Reference 2 contains extensive cost information for SCR catalysts to achieve 80% - 90% reduction from various inlet concentrations to 9 ppmv NOx outlet concentration. The gas turbines in the SCAQMD currently have inlet NOx concentrations in the range of 6 to 2.5 ppmv. An incremental reduction of 80% - 90% is needed to reach 2 ppmv NOx. Staff assumed that the entire SCR costs in Reference 2 can be used to estimate the "incremental" costs for the SCRs at the refineries to reach 2 ppmv. The estimated PWVs based on Reference 2 are $4.13 million for an SCR for a 7 MW turbine, and $22.44 million for an SCR for ~~a~~an 83 MW turbine.

Reference 3 contains the total installed costs and annual operating costs for conventional SCR to reach 79% NOx removal efficiency for a 4.2 MW, 23 MW and 161 MW turbines. Staff assumed that these costs can be used to reflect the "incremental" costs for the scenarios in the SCAQMD. Staff's estimate of the incremental PWVs for SCRs would be $4 million for the 4.2 MW gas turbine, $11 million for the 23 MW gas turbines, and $41 million for the 161 MW gas turbines.

Costs for Cheng Low NOx

Cheng Power Systems provided the following information on costs for CLN to meet 2 ppmv NOx.[20-21] In a presentation to the SCAQMD staff, Cheng compared the costs to operate a simple cycle 85 MW gas turbine with a Cheng cycle gas turbine to show that within a year of operation, the CLN would generate $9 million savings by reducing heat rate and increasing power, and that savings would offset the $5.5 million installation costs for the CLN.[21] The costs for Cheng Low NOx are listed in Tables C.5 and C.6.

Table C. 5 - Projected Income Gain Due to Power Increase for Cheng Low NOx

Engine	Power (MW)	Percent Power Increase
RR 501 KB series	5.2	20%
RR Avon 1535	15	20%
GE LM2500	22	20%
GE 6B	39.5	20%
LM 6000 PC	43	16%
GE 7EA	85	20%

Note: For GE 6B, the increase in power during summer was from 34 MW to 42MW.

Table C. 6 - Equipment and Installation Costs for Cheng Low NOx for Various Types of Gas Turbines

Engine	Power (MW)	Hardware	Installation/Software	Total
RR 501 KB series	5.2	$250,000	$125,000	$375,000
RR Avon 1535	15	$500,000	$350,000	$850,000
GE LM2500	22	$950,000	$650,000	$1,600,000
GE 6B	39.5	$1,700,000	$700,000	$2,400,000
LM 6000 PC	43	$1,800,000	$700,000	$2,500,000
GE 7EA	85	$3,000,000	$2,500,000	$5,500,000

Note: The above price assumes a CHP or Combined Cycle Plant with steam heat recovery system available. The extra costs of engine refurbishment or upgrade is to be determined based on a case by case basis and is not included in the above list.

Present Worth Values and Cost Effectiveness

Figure C.5 depicts a cost curve constructed relating the PWVs for the control devices as a function of turbine MW rating. The PWVs were then estimated for all gas turbines/duct burners to achieve 2 ppmv NOx with SCR/CO catalysts or SCR/ASC. See Table C.7. The PWVs with CLN/SCRs could be less if the savings resulting from increasing power would offset the CLN costs.

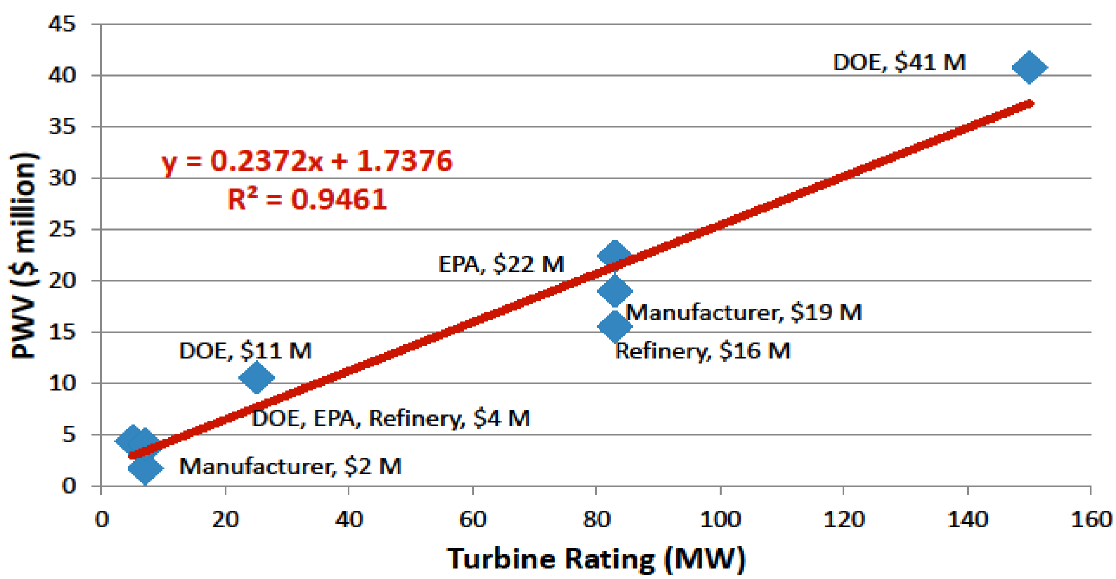

Figure C. 5 - Present Worth Values for Gas Turbines

Table C. 7 – Present Worth Values and Cost Effectiveness for Gas Turbines (December 2014)

No of Units	Rating (MW)	Current NOx Level (ppmv)	Incremental Emission Reduction per Unit from 2005 BARCT (tpd)	Staff's Estimate PWV per Unit ($M)	Incremental Cost Effectiveness ($/ton)
1	59	5.7	0.21	15.7 (new SCR)	8,210
3	46	3-4	0.31	12.6 (new SCR)	4,472
2	30	6	0.20	8.9 (new SCR)	4,851
1	23	5.7	0.14	7.2 (new SCR)	5,631
4	83	2.5-3.5	0.60	4.8 (add catalysts)	870
Total for all 10 units			**4.14**	**97.68**	

Incremental cost effectiveness values were estimated as follows based on the Discounted Cash Flow (DCF) method. A multiplication factor of 1.67 (to account for 25 years life of the SCR/CO/ASC system with frequency of catalyst replacement every 10 years) was used to convert the cost effectiveness estimated using DCF method to the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

It should be noted that the cost estimates in Table C.7 above are conservative for several refineries as discussed below:

- Refinery 5's gas turbines A, B, and C currently emit 3.5 - 4.5 ppmv NOx at 15% O_2. Refinery 5 recently changed the catalysts used in Turbine A and Turbine B from Hitachi to Cormetech, and reduced the catalyst's volume from 2700 cubic feet to 667 cubic feet. The catalyst's volume of Turbine C is 950 cubic feet. The new Turbine D at Refinery 5 uses only 300 cubic feet of Cormetech catalysts to reach 2 ppmv NOx. Turbine D has DLN. Turbines A, B have CLN with steam injection at steam to fuel ratio of 1.5. Turbine C has steam injection at a steam to fuel ratio of 1.3. It should be noted that the steam to fuel ratio for Turbines A and B was permitted at 2.1 – 2.6. Refinery 5 has several options to reach 2 ppmv NOx: 1) add additional catalysts or change to more effective catalysts, 2) increase the steam to fuel ratio, or 3) retrofit with CLN or DLN. Increasing the steam to fuel ratio could add more power to the system and return the investments within a couple years of operation. [20, 28-29]

- Refinery 7 also changed the catalysts to Haldor Topsoe and Cormetech. With the use of more efficient SCR and ASC and additional ammonia, Refinery 7 may be able to reduce the catalyst volume and NOx emissions from 5 ppmv to 2 ppmv NOx without compromising the ammonia slip. [11, 25, 26, 31]

- Refinery 4's two 30 MW turbines currently use water injection, SCR and CO catalysts to achieve 5-6 ppmv NOx. The turbines have permit conditions limiting them to 96 ppmv NOx and 5 ppmv ammonia slip, and 583 tons per year NOx. Refinery 4 can retrofit the unit with steam injection or CLN technology, increase the power and reduce NOx without compromising the ammonia slip. Alternatively, the refinery may change to more effective SCR catalyst type and use ASC to reduce catalyst volume and increase NOx reduction effectiveness without compromising the ammonia slip. [11, 20, 25, 26]

- Refinery 10's gas turbine/duct burner is already at levels below 2 ppmv, thus no incremental costs were estimated for this refinery.

In conclusion, staff proposes to set a new BARCT level of 2 ppmv NOx for refinery gas turbines, aero-derivative as well as frame turbines, because NOx control technologies such as DLE/DLN, CLN, SCR with CO catalysts, SCR with ASC are commercially available and can be used together to achieve 2 ppmv NOx in a cost-effective manner. A level of 2 ppmv NOx is achieved-in-practice for an aero-derivative 7 MW gas turbine/duct burner using SCR and ASC. Two 46MW and 83 MW frame cogeneration units with SCR and CO catalysts were given permits to constructs since 2011 with permit conditions limiting to 2 ppmv NOx, 2 ppmv CO and 5 ppmv ammonia slip.

Consultant's Estimates for SCRs

NEC agreed with staff's proposal of 2 ppmv BARCT level for gas turbines using refinery gas. They proposed adding catalyst to the existing SCRs of the gas turbines to achieve 2 ppmv NOx. Their estimates are generally lower than the staff estimate since they assumed that more catalyst would be used rather than the addition of new SCRs. NEC's estimates are compared to the staff estimate in Table C.8. [33]

Table C. 8 - Comparison of Staff's and NEC's Estimates for Gas Turbines

No of Units	Rating (MW)	Current NOx Level (ppmv)	Incremental Emission Reduction per Unit from 2005 BARCT (tpd)	Staff's Estimate PWV per Unit ($M)	NEC's Estimate PWV per Unit ($M)
1	59	5.7	0.21	15.7 (new SCR)	5.1 (add catalysts)
3	46	3-4	0.31	12.6 (new SCR)	4.0 (add catalysts)
2	30	6	0.20	8.9 (new SCR)	2.6 (add catalysts)
1	23	5.7	0.14	7.2 (new SCR)	2.0 (add catalysts)
4	83	2.5-3.5	0.60	4.8 (add catalysts)	7.1 (add catalysts)
Total for all units			**4.14**	**97.68**	**52.7**

Staff's Recommendation

Staff recommends to set a new BARCT level of 2 ppmv NOx for refinery gas turbines since NOx control technologies such as DLE/DLN, CLN, SCR with CO catalysts, SCR with ASC are commercially available and can be used together to achieve 2 ppmv NOx in a cost-effective manner. A level of 2 ppmv NOx is achieved-in-practice for a turbine/duct burner 1,7 MW cogeneration unit using SCR and ammonia slip catalysts. An 83 MW cogeneration with SCR and CO catalysts was given a permit to construct since 2012 with a permit condition of 2 ppmv NOx.

In summary:

- Incremental Emission Reductions beyond 2005 BARCT level: 4.14 tons per day
- Total Estimated Incremental Costs Range: $52.7 (NEC) - 97.68 M (Staff)
- Average Incremental Cost Effectiveness: 1,452 – 2,692 $/ton (DCF) and 2K – 4.5K $/ton (LCF)

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Appendix D - Coke Calciner

Process Description

Tesoro operates the sole coke calciner in the SCAQMD. Coke calcining is a process to improve the quality and value of "green coke" produced at a delayed coker in a refinery. The green feed, produced by the nearby Carson Refinery, is screened and transported to the coke calcining facility by truck, where it is stored under cover in a coke storage barn. The screened and dried green coke is introduced into the high end of the rotary kiln, 3 ft diameter x 270 ft long, is tumbled by rotation, and moves down the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or oil. The kiln temperatures are in a range of 2000 – 2500 degrees Fahrenheit. The green coke is retained in the kiln for approximately one hour to drive off the moisture, impurities, and hydrocarbon. After discharging from the kiln, the calcined coke drops into a cooling chamber, where it is quenched with water, treated with dedusting agents for dust control, and carried by conveyors to storage tanks. Later, the calcined coke is transported by trucks to the Port of Long Beach for export, or is loaded into railcars for shipments to domestic customers. A simplified process diagram of the calcining process is shown in Figure D.1.

The coke calciner produces approximately 400,000 tons per year of calcined products. This plant is a global supplier of calcined coke to the aluminum industry, and they provide fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses. [1]

Emission Inventory

The 2011 NOx emissions from the coke calciner and current NOx outlet concentration are listed in Table D.1. The total 2011 emissions are 0.55 tons per day. The NOx outlet concentration at 65 ppmv is higher than the 2005 BARCT level of 30 ppmv (0.036 lb/mmBtu).

Table D. 1 - 2011 Emissions for Coke Calciner

Fac ID	Device ID	Device	2011 Emissions (lbs)	Current NOx at 3% O_2 (ppmv)
2	C67	Afterburner	390,625	65
2	D20	Rotary Kiln	11,400	65
Total (tpd)			**0.55**	

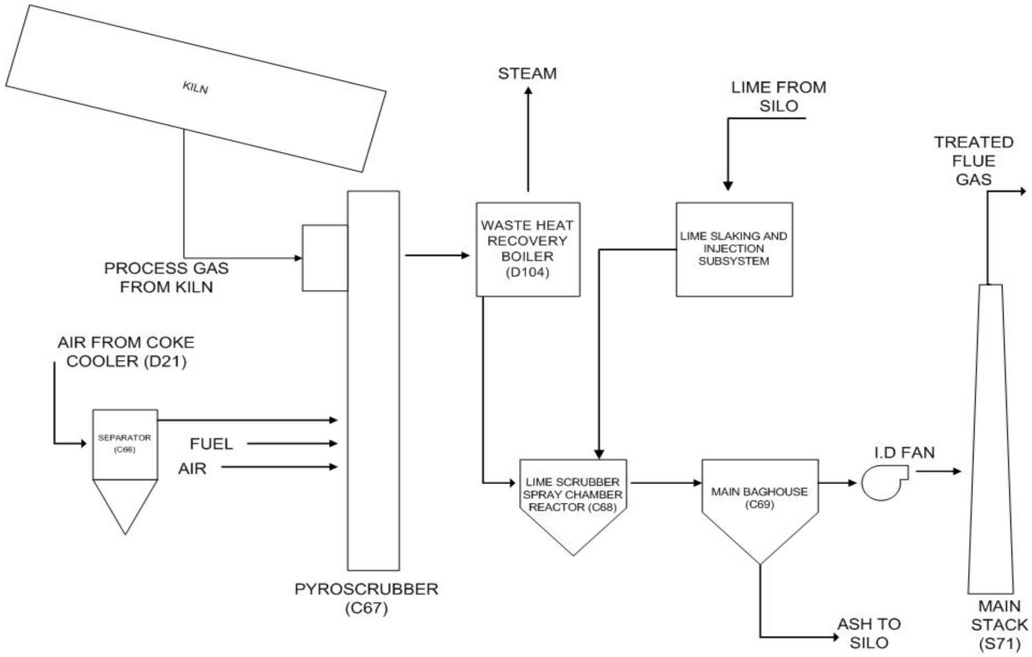

FIGURE 1: SIMPLIFIED PROCESS FLOW DIAGRAM

Figure D. 1 - Coke Calciner Process (Reference 1)

Control Technology

The commercially available control technologies for NOx emissions for the coke calciner are LoTOx and UltraCat, two commercially available multi-pollutant control technologies for low temperature removal of NOx.

LoTOx™ Application

LoTOx™ stands for "Low Temperature Oxidation" process where ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds. LoTOx -is a low temperature operating system, meaning that it does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases. In addition, LoTOx can be used with a wet (or semi-wet) scrubber, and together the system becomes a multi-component air pollution control system that can reduce NOx, SOx and PM concurrently. There are more than 50applications engineered by Linde LLC. since 1997, and more than two dozen applications with EDV™ scrubbers engineered by BELCO Dupont since 2007. [2-3] Applications in gas-fired and high sulfur coal-fired units met 2-5 ppmv. Current installations in refineries met 8-10 ppmv. The technology can be applied to coke calciner, and the manufacturer confirmed that LoTOx can be designed to achieve 2 ppmv NOx from current inlet concentrations of the coke calciner.

The 2010 SOx RECLAIM amendments set a BARCT level of 10 ppmv SOx for the coke calciner. It was determined that wet scrubbers engineered by BELCO, Tri-Mer and MECS were all feasible and cost effective. LoTOx application can be integrated in any of these scrubbers to reduce NOx, SOx, PM and other toxic pollutants. The footprint needed for scrubbers and associated equipment was estimated to be about 30 ft x 40 ft. The facility has not yet installed any scrubber since the adoption of the SOx RECLAIM amendments in 2010.

UltraCat™ Application

UltraCat is also a multi-component air pollution control technology developed by Tri-Mer. UltraCat catalyst filters are composed of fibrous ceramic materials embedded with proprietary catalysts that can remove NOx, SO_2, PM, HCl, Dioxins, and HAPs. The optimal operating temperatures are approximately 350 to 750 degrees F. Aqueous ammonia injected upstream of the catalytic filters is used to remove NOx. NOx removal efficiency is about 95%. Dry sorbent such as hydrated lime, sodium bicarbonate or trona injected upstream of the catalytic filters is used to remove SO_2, HCl, and other acid gases with a removal efficiency of 90% - 98%. Particulate control to a level of 0.001 grains/dcsf and mercury control are also possible. UltraCat filters are arranged in a baghouse configuration with low pressure drop, about 5" water column, and it has a reverse pulse-jet cleaning action (the filters are back flushed with air and inert gas to dislodge the particulate deposited on the outside of the filter tubes). Catalytic filter tubes are replaced every 5 to 10 years. The UltraCat catalytic filtering system is depicted in Figure D.2.

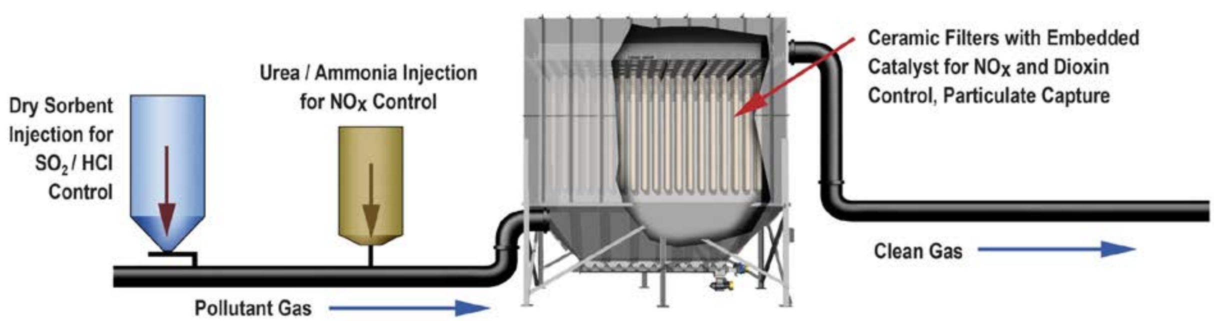

Figure D. 2 - Ultra-Cat Filters (Reference 5)[D2]

Costs and Cost Effectiveness

LoTOx™ Application

Table D.2 contains costs information provided by LoTOx manufacturer.[4] Staff estimated the PWV using the equations below for the Discounted Cash Flow (DCF) method assuming 4% interest rate and 25-years life for the control device. Staff applied a contingency factor of 1.5 to account for any additional costs that might occur. Incremental cost effectiveness was estimated as follows for the DCF method:

$$PWV = 1.5 \times (TIC + (15.62 \times AC)) \quad \text{(Equation 1)}$$
$$CE = PWV / (ER \times 365 \text{ days} \times 25 \text{ years}) \quad \text{(Equation 2)}$$

Where:

TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
ER = Incremental Emission Reductions

In December 2014, the PWV and CE for LoTOx application were estimated to be $22 million and $10,347 per ton NOx reduced per DCF method as shown in Table D.3. The CE would be $17,073 per ton NOx reduced per Levelized Cash Flow (LCF) method.

UltraCat™ Application

Table D.2 contains costs information provided by UltraCat manufacturer.[6] In December 2014, staff estimated the TIC based on the OAQPS EPA Guidelines, i.e. TIC = 1.86 * Equipment Costs. Staff also applied a contingency factor of 1.5 to account for any additional costs that might occur. The PWV assuming 4% interest rate and 25-years life for the control device and the CE were estimated using Equations 1 and 2 shown above. The incremental emission reductions for Ultra-Cat system were estimated to be 0.23 tpd NOx and 0.28 tpd SOx

In December 2014, the PWV and incremental cost effectiveness for UltraCat application were estimated to be $61 million and $13,071 per ton NOx and SOx reduced estimated using DCF method as shown in Table D.3. The incremental cost effectiveness would be $13 K per ton NOx and SOx reduced estimated with the DCF method.

Table D. 2 – Costs of LoTOx and UltraCat for Coke Calciner (December 2014)

2011 NOx emissions	0.55 tons per day NOx
Current NOx concentration	64.95 ppmv NOx
2005 NOx BARCT level	30 ppmv NOx
2010 SOx BARCT level	10 ppmv SOx
2015 BARCT proposed level	2 ppmv NOx
2011 NOx emissions at 30 ppmv BARCT	0.25 tpd
2011 NOx emissions at 2 ppmv BARCT	0.02 tpd
Incremental NOx emission reductions	0.23 tpd
Flue Gas Temp	450 degrees F
Flue Gas Flow	6,806,770 dscfh (113,446 scfm)
Stack Oxygen	5%
Stack Moisture	29.8%
Coke Burned	81,471 tons per year
LoTOx Application for 2 ppmv NOx (97% control)	
Total Installed Costs	$6,250,000
Operating Costs	$544,300 per year
LoTOx Application for 5 ppmv NOx (92% control)	
Total Installed Costs	$6,200,000
Operating Costs	$516,800 per year
Ultra Cat Application for 2 ppmv NOx (97% control)	
Capital Costs of Emission Control	$7,531,774
Operating Costs – Utility, Catalysts, Labor, Maintenance	$1,721,490 per year
Filters replacement frequency	5 years at $215,600 per year

Table D. 3 - Cost and Cost Effectiveness Estimates for Coke Calciner (December 2014)

	Emission Reductions	PWV ($M)	Incremental CE ($/ton)
LoTOx	0.23 tpd NOx	22.13	10,374
UltraCat	0.23 tpd NOx + 0.28 tpd SOx	61.35	13,071

Consultant's Analysis for LoTOx and Staff's Revised Estimates for LoTOx and UltraCat

NEC suggested that a BARCT level of 2 ppmv was not feasible, and recommended 5 ppmv – 10 ppmv BARCT level for the coke calciner. NEC also suggested that a factor of 1.86 to estimate TIC and an adjustment of 1.5 were not conservative enough since space was extremely challenging at the coke calciner facility. A factor of 4.5 – 4.6 was more reasonable. Staff concurred with NEC recommendation and re-estimated the PWVs for the Ultra-Cat application as shown in Table D.4.

Table D. 4 – Revised Cost and Cost Effectiveness Estimates for Coke Calciner (March 2015)

	Staff's Estimates Using Factor of 4.5		NEC's Estimates
	BELCO	**Tri-Mer**	
BARCT Level	10 ppmv	92% control	10 ppmv
Incremental Reductions (tpd)	0.17	0.17+0.28=0.45	0.17
PWV ± 50% ($M)	54.29	91.17	39.50
Cost Effectiveness DCF ($/ton)	$35K/ton	$22K/ton	$25K/ton
Cost Effectiveness LCF ($/ton)	$58K/ton	$36K/ton	$42K/ton

Staff's Recommendation

Staff recommends setting a BARCT level of 10 ppmv NOx for coke calciners because NOx control technologies such as LoTOx and UltraCat are commercially available to achieve this level in a cost-effective manner.

2014 BARCT NOx = (0.08 tpd)(2000 lb/ton)(365 days/yr)/(81,471 ton coke/yr) = 0.8 lb/ton coke

- Total incremental emission reductions beyond 2005 BARCT: 0.17 ton per day
- Total incremental costs: $39.5 million - $91 million
- Total incremental cost effectiveness: $22 - $35 K/~~per~~ ton (DCF) or $36 - $58K/ton (LCF)

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Appendix E - Sulfur Recovery Units/Tail Gas Incinerators

Process Description

A sulfur recovery unit and tail gas treatment unit (SRU/TGTU) at the refineries include a Claus unit followed by an amine absorption unit to recover the sulfur from various gaseous. The SRU (Claus unit) consists of a reactor and series of converters and condensers. Approximately 95% of sulfur from the gaseous streams is recovered after passing through the SRU. The tail gas is then sent to an amine absorption unit, or diethanol amine (DEA), SCOT, Wellman-Lord, and FLEXSORB to absorb and recover the remaining sulfur. Approximately 99% or the remaining sulfur is absorbed and recovered after the amine units. The tail gas is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before emitting to the atmosphere. The refinery SRU/TGTUs including their incinerators are classified as major sources of NOx and SOx.
Since the interception of the RECLAIM in 1993 until 2010, -no Best Available Retrofit Control Technology (BARCT) standards have been established for the SRU/TGTUs and incinerators. The 2010rule amendment included a new BARCT level for SOx at 5 ppmv, 0% O2. At that time, it was determined that Refineries 1, 5, and 6 could retrofit their SRU/TGTUs cost-effectively with wet gas scrubbers (WGS) to further reduce SOx emissions. The construction time was estimated to be about 3 years. [1] As of today, Refineries 1, 5 and 6 did not retrofit any of their existing SRU/TGTUs, instead they selected to purchase RECLAIM Trading Credits or reduce SOx elsewhere in the refinery to comply with their facility emission caps. In 2011, Refinery 5 installed a new SRU/TGTU at their refinery and evaluation of the performance is ongoing.

Emission Inventory

The 2011 NOx emissions from the SRU/TGTUs and incinerators in the SCAQMD and their current NOx outlet concentration are shown in Table E.1. The total 2011 emissions are 0.43 tons per day. The NOx concentrations at the stack vary widely from 6 ppmv to 70 ppmv. It should be noted that their SOx emissions also vary widely from 20 ppmv to 150 ppmv.

Table E. 1 - 2011 Emissions for SRU/TG Incinerators

Unit	Fac ID	Device ID	Device	2011 Emissions (lbs)	Existing NOx @ 3% O2
1	9	1260	INCINERATOR	7,696	66.81
2	6	952	INCINERATOR	41,066	6.57
3	5	911	INCINERATOR	28,379	29.00
4	5	913	HEATER	12,087	29.00
5	5	927	INCINERATOR	14,276	27.00
6	5	929	HEATER	6,080	29.00
7	5	955	INCINERATOR	40,313	29.83
8	5	957	HEATER	13,035	29.83
9	1	910	INCINERATOR	42,273	28.07
10	1	2413	INCINERATOR	22,337	18.33
11	10	175	INCINERATOR	5,674	45.89
12	3	54	INCINERATOR	13,115	55.00
13	3	56	INCINERATOR	4,931	55.00
14	7	436	INCINERATOR	8,030	18.68
15	7	456	INCINERATOR	7,025	31.85
16	8	294	thermal INCINERATOR	49,563	32.00
17	8	292	catalytic INCINERATOR	1,010	not reported
			Total (tpd)	**0.43**	

Control Technology

Commercially available control technologies for NOx emissions are Selective Catalytic Reduction (SCR) and LoTOx. KnowNOx has been installed at two locations in the U.S. however has not yet been tested in any refinery applications. While SCR is considered a high temperature NOx reduction technology, LoTOx and KnowNOx are known for low temperature multi-pollutant control systems since they can be integrally connected with a WGS to reduce NOx, SOx, PM, VOCs, HAPs, and other toxic compounds.

Selective Catalytic Reduction

For the past two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. The advanced SCRs can be designed to reduce 95%-98% NOx emissions from the SRU/TGTUs and incinerators and achieve 2 ppmv NOx while maintaining a low ammonia slip of less than 5 ppmv. [3-14]

LoTOx™ Application

LoTOx™ stands for "Low Temperature Oxidation" process where ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds which can be subsequently removed by absorption in caustic solution, lime or limestone. Please refer to Appendix A for details. There are more than 50 LoTOx applications engineered by Linde LLC., and two dozen applications engineered by BELCO of Dupont for refinery FCCU applications.[15, 22] While BELCO's expertise is in the refinery FCCUs, its sister company MECS has engineered more than two dozen DynaWave scrubbers specifically designed for refinery SRU/TGTUs. Figure E.1 shows a schematic for a DynaWave scrubber. Figure E-2 contains a schematic for LoTOx process incorporated into the DynaWave scrubber.

Currently, LoTOx applications in the FCCU applications have achieved 8 ppmv - 10 ppmv NOx, and 2 ppmv – 5 ppmv NOx in gas-fired and high sulfur coal-fired units. [15, 22] LoTOx technology can be incorporated to the refinery SRU/TGTUs' incinerators and designed to achieve a level of 2 ppmv NOx outlet concentrations.[24]

Table E.3 has a list of the DynaWave installations in the U.S. [25] This is not an inclusive list. In addition to refinery SRU/TGTU applications, DynaWave scrubbers are used in numerous other industrial applications such as sulfuric acid plants, coke calciner, metallurgical plants, secondary aluminum or copper smelters, coal fired heaters and boilers, sulfur pits, platinum recovery plants, cement kilns, meat rendering plants, and medical waste incinerators. DynaWave scrubbers have been used in the industries since 1987.

A BARCT level for SOx was established at 5 ppmv, 0% O_2, annual average in 2010. In 2011, Refinery 5 installed a new SRU/TGTU with a DynaWave scrubber to meet a short-term BACT standard of 10 ppmv. The most recent source test data shows that the DynaWave scrubber meets <1 ppmv SOx, corrected to 0% O_2. Thus, concurrent reductions of NOx and SOx are feasible and cost-effective using a DynaWave and LoTOx combination application.

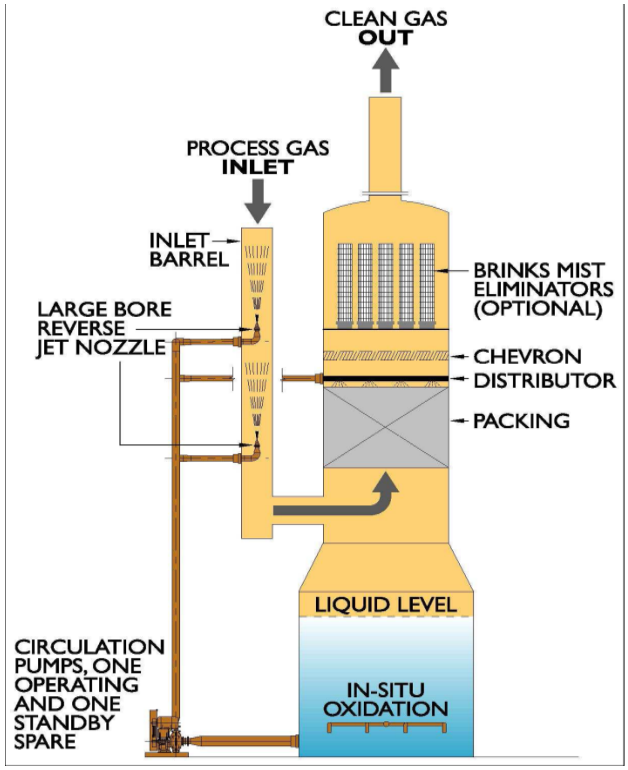

Figure E. 1 - DynaWave Scrubber (Reference 23)

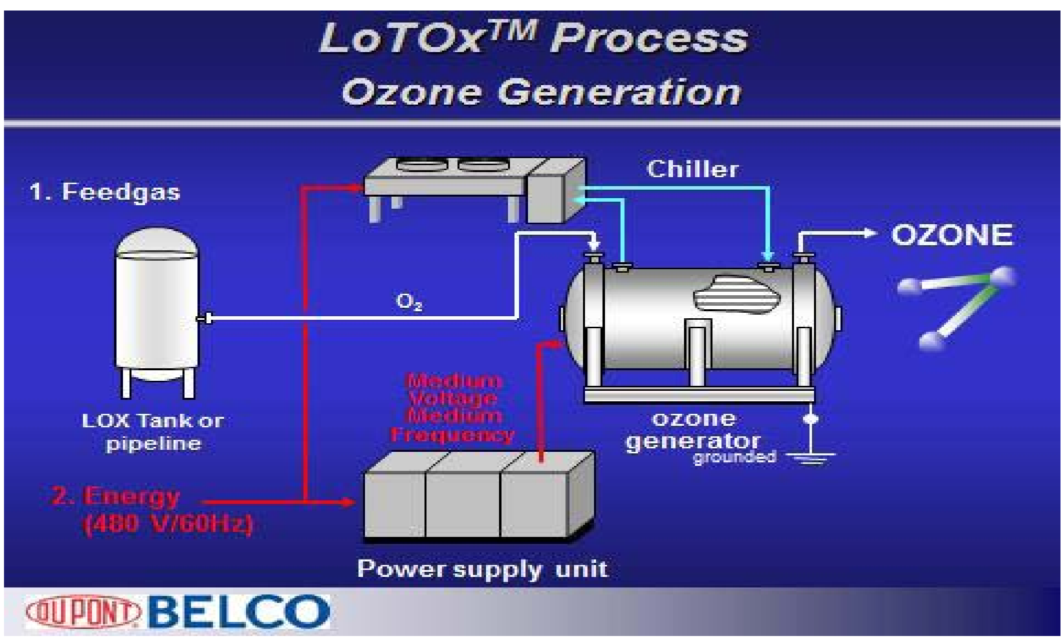

Figure E. 2 - Ozone Generation Process (Reference 23)

Table E. 2 - List of DynaWave Scrubber Installations for SR/TGTUs

Company/Location	StartUp Date	Exit Gas ACFM	Application
KiOR	2012	82,135	BioRefinery FCC Off Gas
Mississippi			Quench, SO_2 and Particulate
Calumet	2010	15,545	40 LTPD SRU Tail Gas Clean Up
Louisiana			SO_2 removal with NaOH
Chevron	2013	27,800	SRU SCOT Tail Gas Clean Up
California			SO_2 removal with NaOH
Sinclair	2009	59,603	FCC Off Gas
Oklahoma			Quench, SO_2 and Particulate
Wyoming Refining	2011	57,746	FCC Off Gas
Wyoming			Quench, SO_2 and Particulate
Pasadena Refining	2008	2,200	S Zorb Off Gas
Texas			SO_2 removal with NaOH
ConocoPhillips	2006	6,700	S Zorb Off Gas
Illinois			PM and SO2 removal with NaOH
Sinclair	2006	9,000	25 LTPD SRU Tail Gas Clean Up
Oklahoma			SO_2 removal with NaOH
Marathon Ashland	2008	10,100	33 LTPD SRU Tail Gas Clean Up
Texas			SO_2 removal with NaOH
Sinclair	2005	12,830	47.5 LTPD SRU Tail Gas Clean Up
Wyoming			SO_2 removal with NaOH
Sinclair	2005	5,700	18 LTPD SRU Tail Gas Clean Up
Wyoming			SO_2 removal with NaOH
ConocoPhillips	2005	2,000	S Zorb Off Gas
Louisiana			SO_2 removal with NaOH
Navajo	2003	100,000	FCC off gas NaOH scrubber for SO_2 and PM
New Mexico			
ConocoPhillips	2003	3,300	S Zorb Offgas
Washington			SO_2 removal using NaOH
Unocal Refining	1993	17,300	Spent sulfuric acid plant
California			
Hess Oil St. Croix	1993	9,400	Spent sulfuric acid plant
Virgin Islands			Gas cleaning for new plant
Sun Refining	1991	2,000	H2S and sour water incinerator
Pennsylvania			Particulate and SO3 removal
BP	1990	130,000	Coke calciner
Washington			PM/SO2 removal with soda ash

KnowNOx™ Application

In lieu of using ozone to convert NO and NO_2 to N_2O_5 and HNO_3, the KnowNOx technology uses chlorine dioxide ClO_2. The conversion reactions (Reactions 12 and 13) are in the gas phase, which can occur much faster than the liquid phase reactions with ozone (Reactions 5 and 6). It takes less than 0.5 seconds to achieve 99.8% or more conversion. The reactions require a smaller vessel in relative to the LoTOx reaction chamber. In addition, the KnowNOx process can simultaneously reduce NOx, SO_2, PM and other contaminants.[26-28]

$5\ NO + 2\ ClO_2 + H_2O \rightarrow 5\ NO_2 + 2\ HCl$	(Reaction 12 - Gas Phase)
$5\ NO_2 + ClO_2 + 3\ H_2O \rightarrow 5\ HNO_3 + 2\ HCl$	(Reaction 13 – Gas Phase)
$5\ SO_2 + 2\ ClO_2 + 6\ H_2O \rightarrow 5\ H_2SO_4 + 2\ HCl$	(Reaction 10)

The conceptual layout for the KnowNOx process is shown in Figure E.3. It includes a three-stages scrubbing system: SO_2 is scrubbed at the 1st stage with a DynaWave scrubber, ClO_2 injected to the 2nd stage converts NO and NO_2 to HNO_3 and other soluble salts, and H_2S generated in the 2nd stage is converted to soluble salts in the 3rd stage. The KnowNOx technology has been installed at two locations in the U.S., however, it has not yet been tested in any refinery applications, and may not yet have been proven at full scale operations.

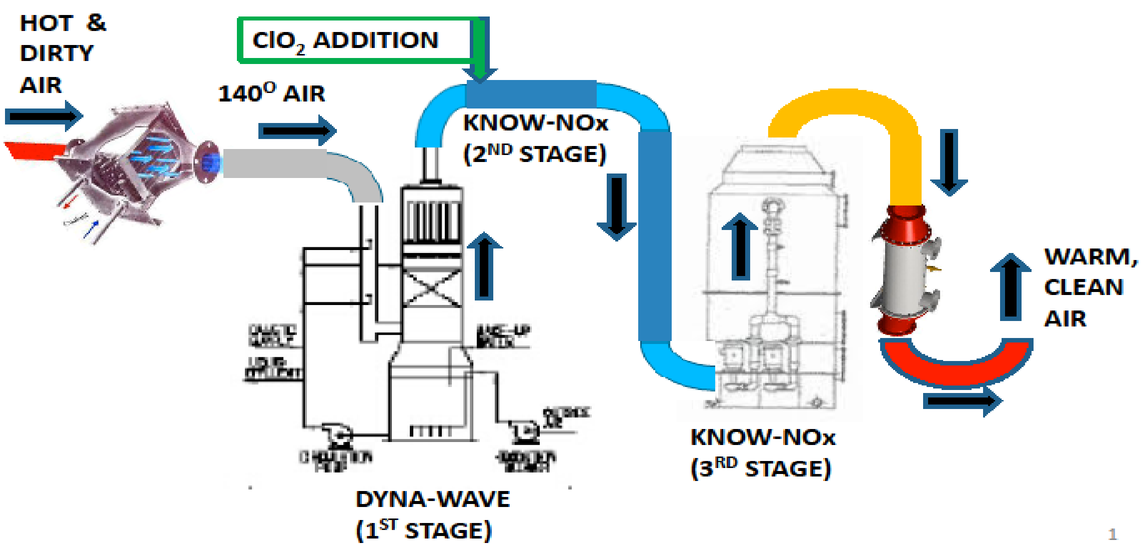

Figure E. 3 – KnowNOx Process (Reference 28)

Costs and Cost Effectiveness

Selected process conditions and the outlet NOx concentrations of the SRU/TGTUs at the refineries in the SCAQMD are listed in Table E.3. To obtain control equipment cost information, staff provided the manufacturers with the information for the three scenarios listed in Table E.4. These scenarios reflect the units with highest emissions and flue gas flow rates from the 17 SRU/TGTUs/incinerators in the SCAQMD.

Staff estimated the PWV for the control system using Equation 1 below assuming 4% interest rate and a 25-years life for the control device:

PWV = (Contingency Factor) x (TIC + (15.62 x AC) + (2.52 x CR)) (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
CR = Catalyst Replacement every 5 years
Contingency factor = 1.5

Staff used the factors in the EPA OAQPS Guidelines to estimate the TIC and a- contingency factor of 1.5 was added to the TIC and AC to account for operational uncertainties. CE was estimated as shown in Equation 2 using the DCF method. For comparison, the incremental cost effectiveness would be about 1.65 higher if it was calculated using the LCF method:

CE = PWV / (ER x 365 days x 25 years) (Equation 2)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

Costs for SCRs

Manufacture A's estimates are summarized below: [13]

- It is feasible to achieve 2 ppmv NOx and 5 ppmv ammonia slip,
- All three scenarios would result in about the same costs,
- Costs for SCR catalysts would be about $600,000 and installation costs about $600,000,
- Add costs for heat exchangers in Scenario 1 and 2, and
- Inlet NOx could be higher but would not affect the overall cost estimates.

Table E. 3 - Process Information and NOx Emissions for SRU/TG Incinerators in SCAQMD

Unit	Fac ID	Device ID	Device	Max Rating (mmbtu/hr)	Flue Gas Flow rate (dscfm)	Flue Gas Temp (degree F)	Existing NOx (ppmv)
1	9	1260	INCINERATOR	36			66.81
2	6	952	INCINERATOR	100	34,640	1,080	6.57
3	5	911	INCINERATOR	30	12,500	515	29.00
4	5	913	HEATER	25	12,500	515	29.00
5	5	927	INCINERATOR	30	12,500	570	27.00
6	5	929	HEATER	25	12,500	570	29.00
7	5	955	INCINERATOR	58	14,500	520	29.83
8	5	957	HEATER	41	14,500	520	29.83
9	1	910	INCINERATOR	45	32,167	1,260	28.07
10	1	2413	INCINERATOR	40	27,167	1,292	18.33
11	10	175	INCINERATOR	10			45.89
12	3	54	INCINERATOR	52			55.00
13	3	56	INCINERATOR	45			55.00
14	7	436	INCINERATOR	20			18.68
15	7	456	INCINERATOR	20			31.85
16	8	294	thermal INCINERATOR	28	23,284		32.00
17	8	292	catalytic INCINERATOR	15			

Table E. 4 – NOx and SOx Performance of SRU/TG Applications in SCAQMD

	Scenario 1 Refinery 6	Scenario 2 Refinery 1	Scenario 3 Refinery 5
Incinerator Rating	100 mmBtu/hr	45 mmBtu/hr	100 mmBtu/hr (note)
Average flue gas flow rate	36,000 dscfm	32,000 dscfm	14,500 dscfm
Temperature	1,100 degrees F	1,200 degrees F	520 degrees F
O2 %	2.5%	6% - 8%	4%
Current NOx concentration	21 ppmv	28 ppmv	30 ppmv
Current SOx concentration	40 ppmv	75 ppmv	20 ppmv

Note: Incinerator 58 mmBtu/hr and heater 41 mmBtu/hr are vented to a common stack

Manufacturer B's estimates are summarized below: [14]

- It is feasible to achieve 2 ppmv NOx and 5 ppmv ammonia slip,
- SCR costs for Scenario 1 and 2 were estimated to be about $461,000 for SCR at 80% NOx control efficiency. SCR costs for Scenario 3 would be about 10% less than Scenario 1 and 2.
- Costs for a system at 90% control efficiency would be about 5% higher than the costs for a system at 80% control efficiency.
- Costs for a system with 95% control efficiency would be about 10% higher than the costs for a system at 80% control efficiency.
- Estimated costs would not vary with inlet NOx concentration
- SCR footprint and dimension:
    - Catalysts with 1 layer and 1 module for a system with 85% control efficiency. Add 3 in of catalysts for a 95% control efficiency system
    - Add 2 ft in each direction for structural steel, and 6" for insulation
    - SCR overall dimension: 15 ft x 15ft x 15 ft
- Heat exchanger would be required for Scenarios 1 and 2 to lower the temperatures to the optimum temperatures of about 750 degrees F
    - Heat exchanger would cost about $100,000
    - Dimension for a horizontal flow heat exchanger: 6 ft Dia x 6ft - 10 ft L.
- Ammonia usage (19% aqueous ammonia):
    - 11.1 lb/hr for 80% removal, 12.1 lb/hr for 90% control, 12.6 lb/hr for 95% control
    - About $82,000 per year NH_3 costs and $40,000 miscellaneous for a 95% control
    - Dimension of 2000-gallons NH_3 storage tank: 4 ft D x 24 ft L, or 6 ft D x 10 ft L.
    - Ammonia storage tank costs $15,000 (30 days supply)
- Catalyst replacement would be every 5 years. Replacement frequency would depend on actual flue gas constituents and could be guaranteed for a turnaround cycle.

Costs for LoTOx™ Applications

MECS's cost estimates for LoTOx system to reduce NOx emissions are shown in Table E.5. MECS also provided costs for DynaWave and LoTOx in one system to reduce both NOx and SOx emissions as shown in Table E.5. [24]

Table E. 5 – Cost Information Provided by MECS

	Scenario 1		Scenario 2		Scenario 3	
	LoTOx	Dynawave LoTOx	LoTOx	Dynawave LoTOx	LoTOx	Dynawave LoTOx
Inlet Temp, degrees F	1,100	1,100	1,200	1,200	520	520
Inlet Flow, scfm	38,710	38,710	34,409	34,409	15,761	15,761
Outlet Temp, degrees F	158	158	161	161	139	139
Outlet Flow, scfm	52,782	52,782	48,329	48,329	18,021	18,021
Total Installed Costs, $	5,666,000	8,432,000	5,605.000	8,311,000	4,903,237	6,907,000
Operating Costs, $/yr	89,356	260,600	98,713	276,110	47,000	73,650

Costs for KnowNOx™ Applications

Costs provided by KnowNOx for its system to reduce only NOx emissions are shown in Table E.6. KnowNOx also provided costs for DynaWave scrubber in combination with its technology to reduce both NOx and SOx emissions.[29]

Table E. 6 – Cost Information Provided by KnowNOx

	Scenario 1		Scenario 2		Scenario 3	
	KnowNOx	Dynawave KnowNOx	KnowNOx	Dynawave KnowNOx	KnowNOx	Dynawave KnowNOx
Inlet Flow, scfm	36,000	36,000	32,000	32,000	14,500	14,500
Total Installed Costs, $	1,420,225	4,220,226	1,398,286	4,198,286	1,401,825	3,402,226
Operating Costs, $/yr	108,284	289,936	112,957	295,948	198,729	227,337

In 2014, staff estimated that SCRs, LoTOx and KnowNOx would be cost-effective for 10 SRU/TGTUs (out of 17 units) at Refineries 1, 5, 6 and 8. The PWVs for SCRs, LoTOx and KnowNOx were estimated to be $48.7 M, $68 M and $39 M respectively. The cost effectiveness for the 7 SCRs was estimated to be $15 K per ton NOx reduced (DCF) and $25 K per ton NOx reduced (LCF) as shown in Table E.7.

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs and LoTOx

NEC confirmed that the 2 ppmv proposed BARCT level is feasible for the refinery SRU/TG incinerators. However, the consultants indicated that the factor of 1.86 from the EPA OAQPS Guidelines was low and suggested staff used a factor of 4.5. NEC also recommended using SCRs with 3 layers of catalysts and added the costs of waste heat boilers, new ammonia tanks and associated equipment. A comparison of NEC's and staff's estimates is shown in Table E.7.

Table E. 7 - Comparison of SCR Costs Estimated by Staff and NEC for SRU/TGTUs (December 2014)

	Staff's Estimates for SCRs	NEC's Estimates for SCRs
PWVs for SCRs	$ 48.7 M	$ 96.4 M
Cost Effective Units	10	9
Emission Reductions	0.35 tpd	0.32 tpd
Cost Effectiveness (DCF)	15,233 $/ton	33,014 $/ton

Staff revised the cost estimates using the factor of 4.5 recommended by NEC. The revised estimates are shown in Table E.8. Per these revised estimates, there would be 9 cost effective SRU/TG units with a total incremental emission reductions of 0.32 tpd at PWVs of $82.5 M for SCRs or $105.8 M for LoTOx applications.

Table E. 8 - Revised Cost and Cost Effectiveness Estimates for SCRs and LoTOx for SRU/TGTUs (March 2015)

Fac ID	Dev	SCR			LoTOx		
		AQMD ($M)	**Reductions (tpd)**	**AQMD CE ($/ton)**	**AQMD ($M)**	**Reductions (tpd)**	**AQMD CE ($/ton)**
6	D952	16.2	0.05	33,298	22.7	0.05	46,458
5	911/913	11.3	0.05	23,491	18.9	0.05	39,321
5	927/929	11.3	0.03	46,697	18.9	0.03	78,167*
5	955/957	11.3	0.07	17,818	18.9	0.07	29,826
1	910	17.3	0.06	34,379	22.7	0.06	45,127
1	*2413*	*16.9*	*0.03*	*63,593***	*22.7*	*0.03*	*85,404***
8	294	15.2	0.06	25,805	22.7	0.06	38,490
Total for cost-effective units		**82.5**	**0.32**	**28,270**	**105.8**	**0.29**	**39,963**

*this unit was cost effective using SCR technology thus was included in the revised analysis. ** this unit was not cost effective using either SCR or LoTOx thus was not included in the revised cost analysis.

Staff's Recommendation

Staff recommends to set a new BARCT level of 2 ppmv NOx for SRU/TG incinerators (95% control efficiency) because NOx control technologies such as SCR and LoTOx (or KnowNOx) with DynaWave scrubbers are commercially available and can de designed to achieve 2 ppmv NOx in a cost-effective manner.

In summary:

- Incremental Emission Reductions beyond 2005 BARCT level: 0.32 tons per day
- Number of cost effective units: 9
- Total Incremental Costs: $83 M ± 50% with SCRs - $106 M ±50% with LoTOx
- Average Incremental Cost Effectiveness (DCF method):
  - $28K per ton NOx reduced with SCRs
  - $40K per ton NOx reduced with LoTOx applications
- Average Incremental Cost Effectiveness (LCF method):
  - $46K per ton NOx reduced with SCRs
  - $66K per ton NOx reduced with LoTOx applications.

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Appendix F - Comparative Analyses for FCCUs

This appendix provides a comparison of the selective catalytic reduction (SCR) design configuration, total installed cost (TIC) calculation and present worth value (PWV) estimation methodologies used in the staff and NEC cost effectiveness calculation for the FCCUs. Table F.1 summarizes the basic comparison. Variations in the SCR size, cost assumptions, TIC and PWV estimation methodology are provide in a side by side comparison for evaluation.

Table F.1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	**NEC's Design**
SCR Configuration	2-Catalyst layers 3-Beds: 1-reserve	3-Catalyst layers 3-Beds: all used
Cost Models	SCR costs directly provided by Refinery 1 (2 catalyst layers) and the manufacturers (2-catalyst layers) SCR cost for Refinery 5, 6 and 7 scaled to Refinery-1 based on flow rate. SCR cost for Refinery 4 and 9 provided directly by the manufacturers.E	SCR cost provided by vendor (2 catalyst layers 12.8 feet per second). SCR vendor based costs curve (scaled for 3-layers, 10 feet per second) With NEC modifications and refinery input including: • 1.35 bid conditioning factor, • 1.75 labor factor, and • 4.5 TIC factor
Additional Costs		Waste Heat Boiler Modifications, New CEMS, NH3 Storage
Refinery Cost Application		
Refinery-1	Refinery -1 data	N/A
Refinery-4 & 9	EPA Methodology with 1.5 contingency for PWV. NEC additional costs assumed in the contingency factor.	Cost Curve
Refinery-5	Scaled to Refinery-1	Cost Curve
Refinery-6	Scaled to Refinery-1	Cost Curve
Refinery-7	Scaled to Refinery-1	Cost Curve
All Refineries	SCR cost provided by manufacturer (2 catalyst layers) with NEC additional costs included.	

Summary of Staff's Approach

Staff presented two approaches to estimate the SCR PWV for the 6 FCCUs operating in the Basin. (Note: two FCCUs are not controlled using SCRs). The first approach estimated PWV using data directly obtained from Refinery1 to establish PWV, while 3 additional SCR PWV were scaled from the Refinery 1 estimate. Two additional SCR PWV profiles were estimated using manufacturer provided cost information and the EPA cost model with a 150 percent contingency.

The second approach used the NEC model for the manufacturer's SCR designed for 2-catalyst layers. The two methods provided a range of PWV and CE as reported in Appendix A.

Approach #1

- Refinery 1 submitted capital costs and annual operating costs for their FCCU SCR in 2013. The FCCU SCR was installed in 2003 with 2 layers of catalysts and 1 spare layer and achieved 2 ppmv NOx.

- Using the cost information submitted directly by Refinery 1 to estimate the PWV would result in $41 M. Using the NEC equation (derived for a 3-catalyst layer SCR from data provided by a manufacturer) the PWV would result in $52 M. The PWV estimated based on NEC's approach and equation would be about 26% higher than that estimated using the actual costs submitted by Refinery 1.

- Staff scaled the Refinery 1 SCR PWV cost using the of Refinery 1 SCR and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power to project PWV for Refineries 5, 6, and 7.

- PWV for Refineries 4 and 9 was estimated using SCR manufacturer cost data and the U.S. EPA Guideline approach with a 150 percent contingency markup.

Approach #2

Staff used the NEC approach to develop a cost curve based on the SCR manufacturer's design of 2-catalyst layers.

The NEC cost assumptions included:

- 1.35 for a bid conditioning factor
- 1.75 adjustment for labor
- 4.5 factor to relate the equipment costs to a TIC
- Staff added the NEC estimated costs of a waste heat boiler, new CEMS, and costs of ammonia storage tank.

PWV estimated for 2-catalyst layers vs. 3-catalyst layers

A comparison of the PWV estimates calculated for Refinery 9 using the manufacturer 2-layer SCR model (with and without selected cost markups) and the NEC 3-layer SCR model and the EPA methodology is presented in Table F.2.

Table F. 2 - Comparison of Cost Estimates for FCCU's SCR

	NEC's Design	Manufacturer's Design (note)				EPA Methodology
Layers of catalysts	3	2	2	2	2	with 50%
1.35 Markup	Yes	Yes	No	Yes	No	Contingency
1.75 Markup	Yes	Yes	Yes	No	No	
Total Installed Costs , $M	**31.6**	**26.4**	**21.5**	**18.3**	**15.5**	**16.13**
PWV, $M	**39**	**32**	**27**	**24**	**21**	**19**

Note: The TIC include the costs of SCR provided by vendor to NEC ($1.78 M) for a FCCU with a feed rate of 60 thousand barrels, the costs of waste heat boiler ($4.5 M) estimated by NEC, the costs of CEMS ($1.5 M) estimated by NEC, the costs of ammonia storage tank ($1.5 M) estimated by NEC, and annual operating costs estimated by NEC.

The PWV for the manufacturer's design with no markup ($21 M) was only 10% more than staff's estimates using the EPA methodology. With equivalent markup factors applied, the manufacturer's 2-layer model was approximately 22 percent lower in cost than the 3-layer model. This compares well with the 26 percent PWV adjustment between the NEC 3-catalyst layer model and staff's estimate for the 2-layer SCR noted for Refinery 1 in Approach #1. Also, for the EPA methodology, staff used a 50% contingency factor to account for the uncertainty in the complex refinery environment compared to the EPA OAQPS Guidelines recommended a level of 30%.

The cost curve described in Approach #2 was used estimate the PWV of the SCR system with two NEC markup factors for an SCR provided by vendor with 2 layers of catalysts, a new waste heat boiler, a new CEMS, and a new ammonia storage tank. The curve was applied to the boiler FCCU feed rates to estimate the PWVs of five SCRs at the refineries are listed in Table F.3.

Table F. 3 - Comparison of Cost Estimates for SCRs with and without Markups

	Feed Rate (10^3Barrels per Day)	AQMD's Estimates PWV ($M)	Manufacturer's costs with 2 layers of catalysts and 2 levels of markups PWV = 2.8013*(Feed Rate)$^{0.6}$ ($M)
Ref 5	71	33	36
Ref 6	90	57	42
Ref 7	55	27	31
Ref 4	34	16	23
Ref 9	55	19	31
Total		**152**	**163**

Summary of NEC's Approach

NEC based their estimation of PWV on a manufacturer's detailed cost profile for a 3-bed SCR for Refinery 9 where 2 layers were designated for catalyst loading. NEC's preferred engineering design required 3 catalyst layers (4-bed design with on bed in reserve) to meet the 2 ppmv emissions level. As such, the manufacturers design was scaled upward based on additional catalyst volume and associated costs as well as adjustments to the space velocity. The revised design was then subjected to the same cost assumptions stated in staff approach #2. PWV was estimated for the several feed rates to establish a distribution that was the basis for a power law cost curve. (See Addendum-1 to the staff report for NEC's analysis).

During the review of the NEC report, it was noted that the initial feed rates used by NEC in estimating PWV were not consistent with reported levels (Table F.4).

Table F. 4 - Refinery Feed Rates of FCCUs in SCAQMD

Refinery No.	**4**	**7**	**9**	**5**	**6**
Back-calculated feed rates used by NEC, 10^3 Barrels/Day	58	68	60	79	79
Feed rates reported in SOx RECLAIM, 10^3 Barrels/Day	30	55	55	71	90
Feed rates shown in the Jan 22 14 Working Group Meeting, 10^3 Barrels/Day	34	49	52	67	84

- The NEC 3-layer SCR model PWV estimates were recalculated using the reported feed rates and the revised PWVs were reduced by 26% to reflect the difference between the NEC cost curve estimate for Refinery 1 and the PWV determined by staff in Approach #1 above using the reported data.

- A comparison of the revised NEC cumulative PWVs adjusted by the 26 percent factor (2 vs. 3 catalyst layers for Refinery-1) with the staff approach #1 methodology were in good agreement (Table F.5).

Table F.5 – Estimates of Costs Adjusted to Refinery Feed Rates and Using the Refinery 1 26 Percent PWV Adjustment

	Feed Rate (10^3 Barrels/D)	Staff's Estimates ($M)	Revised NEC Estimates ($M)	Ratio Revised NEC/Staff's Estimates
Ref 5	71	33	34	1.03
Ref 6	90	57	40	0.70
Ref 7	55	27	29	1.07
Ref 4	34	16	22	1.38
Ref 9	55	19	29	1.53
Total		**152**	**154**	**1.01**

Summary of the Analysis

Staff based its cost estimates on the application of a 2-catalyst layer SCR design for each of the refineries. The analysis focused on Refinery 1 which had achieved in practice an emissions level of 2 ppmv with the 2-catalyst layer design.

NEC recommended a more conservative 3-catalyst layer design based upon their experience with refinery controls installations.

Both designs have nearly equivalent estimated PWV when the 3-to-2 catalyst layer assumption is normalized.

The costs estimated by staff provide a CE range between $18K and $20 K per ton of NOx reduced. Using the NEC 3-Layer approach, the upper value of -CE would be- $29K.

Appendix G - Comparative Analyses for Boilers & Heaters

This appendix provides a comparison of the control equipment design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the boiler and heater cost effectiveness calculation. Table G.1 summarizes the basic comparison. Variations in the selective catalytic reduction (SCR) size, cost assumptions and TIC and PWV estimation methodology are provided in a side by side comparison for evaluation. As previously stated in Appendix B, the NEC design to reach 2 ppmv relies on the use of 3 layers of catalyst and 1 additional layer for an Ammonia Slip Catalyst (ASC) bed. Staff's estimate is based on existing SCR applications achieved-in-practice and alternate control methodologies identified in the analysis.

Table G.1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	NEC's Design
SCR Configuration	1-Catalyst layers	3-Catalyst layers 1-ammonia bed 4-Beds: all used
Alternate Configurations	Great Southern Flameless Heaters ClearSign Duplex burners	
Cost Models	Refinery survey data, refinery consultant's data, cost estimates from SCR manufactures, Great Southern and ClearSIgn were used to construct maximum PWV of SCRs for 5 ppmv NOx for 5 ranges of boiler/heater firing rates.	SCR Vendor Based application (scaled for 4-layers) with NEC modifications and refinery input. Additional cost for induced draft fan
	CPWV of SCRs for 2 ppmv NOx = 1.1 * PWV of SCRs for 2 ppmv emissions limit for 5 ranges of boiler/heater firing rates	Individual PWV Costs curves for 5 ppmv and 2 ppmv emissions limits based on maximum firing rate
Refinery Application	83/212 Units ≤ $50,000/Ton	46/212 Units ≤ $50,000/Ton

Summary of Staff's Approach

- Cost data for all feasible control technologies including SCRs, LoTOx, Great Southern flameless heaters, and ClearSign duplex burners was analyzed.

- Three sets of cost data were used to construct the cost curve in Figure G.1:

    - Group 1 data set: Survey cost data provided directly by the refineries for SCRs that achieved 1.6 – 3.5 ppmv NOx was used. The refineries provided actual equipment costs, total installed costs (TIC) and annual operating costs. The actual costs were increased to 2014 dollars. From this set of actual costs: TIC = 3.87 x equipment costs, and PWV = 1.052 x TIC = 4.07 x equipment costs.

- Group 2 data set: Cost data estimated by the consultants for a refinery for future SCR projects was used. The consultants of the refinery applied a factor of 4.0 to estimate TICs for future projects (i.e. TIC = 4.0 x equipment costs), and staff estimated the PWVs consistently with the actual cost data in Group 1, PWV = 1.052 x TIC.

- Group 3 data set: Equipment costs provided by control equipment manufacturers for SCRs, Great Southern Flameless heaters, and ClearSign Duplex burners were used. TICs were estimated using a factor of 4.0, and PWVs were estimated using a factor derived from the Group 1 data set.

- Staff selected the upperbound PWVs shown in Figure G.1 for the costs of control devices that can achieve 5 ppmv NOx. Staff added another 10% to the upperbound costs in Figure 1 to derive the costs for control devices that can meet 2 ppmv NOx:

$5.5 M for units with maximum rating ≤ 100 mmBtu/hr
$11 M for units with maximum rating > 100 – 200 mmBtu/hr
$22 M for units with maximum rating > 200 – 400 mmBtu/hr
$33 M for units with maximum rating > 400 – 600 mmBtu/hr
$49.5 M for units with maximum rating > 600 mmBtu/hr

The upperbound PWVs derived were higher than all of the actual costs from the Group 1, 2 and 3 data sets. For example, the actual reported costs for a 650 mmBtu/hr heater was about $42 M and the upperbound PWV that staff derived based on this approach was $49.5 M.

Summary of NEC's Approach

NEC concurred that the 2 ppmv BARCT level is feasible for refinery boilers/heaters >40 mmBtu/hr. However, NEC stated their recommendation required using SCRs with 4 layers of catalysts [3-layers plus 1-layer of ammonia slip catalyst (ASC)].

- NEC used the approach described in Appendix F whereby a manufacturers design and quote for a 2-catalyst layer SCR (with 1-additional bed) was structured to accommodate a 4-layer SCR with 3-catalyst layers and an ammonium slip catalyst layer. Their estimate also included costs for a new CEMS, ammonia system and induced draft fan installation.

- NEC adjusted the manufacturer's design to 10 ft/sec velocity, increased the cross section area, added a 3rd and a 4th layer of catalysts, increased the SCR dimension to 20 feet width x 19.2 feet length x 44 feet height, and increased the equipment costs to $2.48 M.

NEC estimated annual costs for ammonia usage, utility, catalyst replacement, and miscellaneous maintenance and developed 2 sets of PWV cost curves based on applying the NEC SCR model to a range of firing rates.

The PWVs were estimated by NEC as follows:

PWV = 3.1354 x (Maximum rating of boiler or heater) $^{0.3947}$ for 5 ppmv SCRs
PWV = 3.4838 x (Maximum rating of boiler or heater) $^{0.3947}$ for 2 ppmv SCRs.

NEC provided two curves for 2 ppmv SCR and 5 ppmv SCR that staff could use to estimate the incremental costs for boilers/heaters >110 mmBtu/hr. Figure B.3 is revised below (Figure G.1) to include the NEC cost curves. The difference in the cost curve PWV project is most pronounced for the smaller units with maximum firing rates 200 mmBtu or less. As the firing rate increases beyond 500 mmBtu, the curves begin to converge.

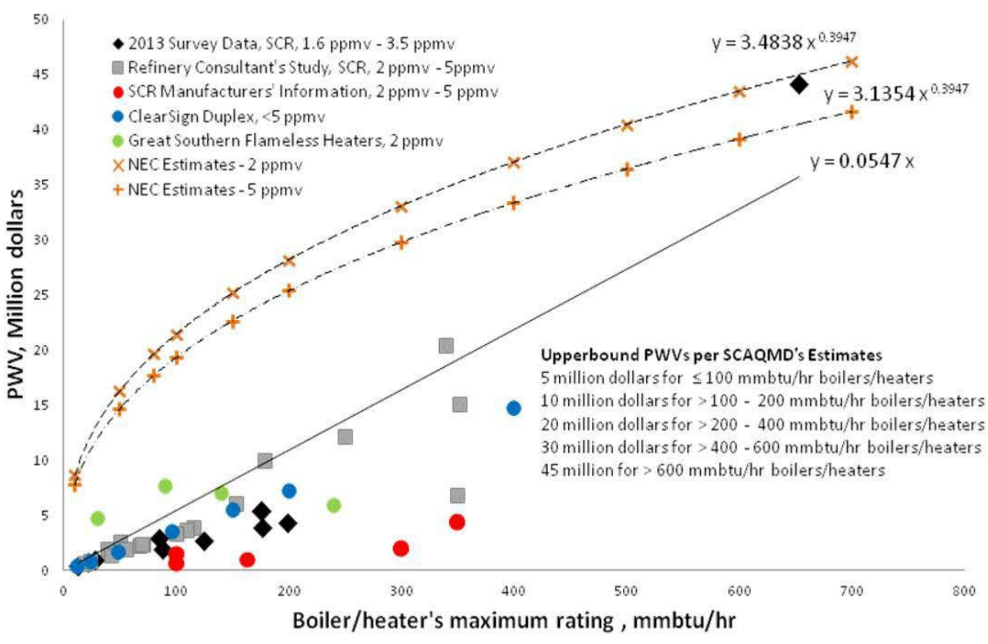

Figure G. 1 - Present Worth Values for SCRs (December 2014)

Summary and Discussion

The two methodologies employed to develop the PWVs for SCRs- are inherently different. The resulting number of units determined to be cost effective at 2 ppmv NOx at an under $50,000 per ton threshold varied from 48 using the NEC method to 103 units using the staff method. Using the NEC method resulted in 0.33 TPD less NOx reductions. As is noted in the following discussion, SCRs have achieved-in-practice 2 ppmv NOx in the Basin using the 1-catalyst layer SCR model. As a consequence of the uncertainty in PWV between the use of the two cost methodologies and CE estimation, staff is proposing to reduce the overall RECLAIM RTC reductions by the 0.33 TPD as a component of the overall adjustment from 14.8 to the 14.0 TPD proposal.

~~There are several heaters in the SCAQMD that have SCRs built to achieve 5 pppmv NOx, and these SCRs actually achieved 1.6 ppmv – 2.7 ppmv as reported by the refineries. All of these SCRs have 1 layer of catalysts. The catalyst depth is about 2 – 3 feet, and the catalyst volumes range from 62 – 623 cubic feet as shown in Table G-2. By comparison, the Refinery 1 FCCU SCR has 2 layers of catalyst with a total catalyst depth of 9 feet. The dimensions of the Refinery 1 FCCU SCR listed in Table G.2 are compared to the dimensions of the existing SCRs for refinery heaters. Refinery heater SCRs are more compact with smaller volumes of catalysts compared to FCCU SCRs. In contrast, Refinery 1 FCCU's feed rate is about 95,000 barrels per day (B/D) yet Refinery 1 FCCU SCR achieved less than 2 ppmv NOx using only 2-catalyst layers.~~

Table G. 1 – Performance Levels and Dimensions of Existing SCRs for Heaters in SCAQMD Compared to Existing SCR for an FCCU

	Ref 9 3 hydro treating heaters	Ref 5 isomax heater	Ref 5 crude heater	Ref 9 crude heater	Ref 5 3 coker heaters	Ref 5 4 ref-ormers	Ref 1 FCCU
Maximum rating, mmbtu/hr	63	78	83	85	528	589	95,000 B/D
NOx, survey, ppmv	**2.7**	**2.3**	**2.7**	**3.3**	**2.7**	**1.6**	**< 2ppmv**
NOx, permit limit, ppmv	n/a	5	5	5	n/a	5	
SCR, Width, ft	5	20	4	17	18	13	30
SCR, Length, ft	6	7	6	7	18	16	29
SCR, Height, ft	4	6	3	12	20	3	49
Total SCR volume, ft3	110	798	note 1	1,380	6,300	note 1, 2	41,748
Existing catalyst volume, ft3	92	92	62	96	623	537	**6,210**
No of catalyst layers	1	1	1	1	1	1	**2 (1 spare)**
Catalyst depth, ft	3	2	3	2	2	3	**4.5**

Note:

1) The SCR height stated in the permit is likely for the catalsyts and not for the overall SCR .

2) District recently approved a change of catalysts for this SCR. New catalyst volume is 424 ft3, guarantee of <=5 ppmv NOx

Appendix H - Comparative Analyses for SRU/TGUs

This appendix provides a comparison of the proposed control equipment design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the SRU/TGTU cost effectiveness calculation. Table H.1 summarizes the basic comparison. Staff evaluated selective catalytic reduction (SCR), LoTOx, and Know-NOx technologies while NEC expressed concerns on the effectiveness and applicability of technologies other than SCR. Where comparable, variations in the SCR size, cost assumptions and TIC and PWV estimation methodology are provide in a side by side comparison for evaluation.

Table H-1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	NEC's Design
SCR Configuration	1-Catalyst layer 2	3-Catalyst layers 3-Beds: all used
Alternate Configurations	LoTOx ozone injection coupled with either a Belco EDV or DynaWave scrubber Know-NOx ClO2 injection coupled with a DynaWave scrubber	N/A N/A
Additional Equipment	Heat Exchanger	Waste heat boiler (heat exchanger)
Cost Models	Cost estimates: SCR manufacturers LoTOx and Know-NOx PWV estimated using EPA format (1.86 TIC) with 1.5 contingency factor Costs revised to reflect NEC PWV 4.5 factor	SCR Vendor Based application (scaled for 3-layers) with NEC modifications and refinery input.
Refinery Application	9 Units ≤ $50,000/Ton	9 Units ≤ $50,000/Ton

Summary of Staff's Approach

- Cost data for all feasible control technologies including SCR, LoTOx, and KnowNOx were analyzed. SCR and LoTOx are used in refinery applications such as boilers, heaters, and FCCU while KnowNOx currently does not yet have any refinery application.

- Process information for three representative scenarios was sent to 2 SCR manufacturers, MECS (LoTOx), and KnowNOx. Cost data provided by the manufacturers using the EPA

OAQPS Guideline methodology were used to estimate the TIC. This approach was used in the 2005 RECLAIM rule amendment.

Instrumental = 10% x Equipment costs
Sales Tax = 9% x Equipment costs
Freight = 5% x Equipment costs
Total Equipment Costs = 1.24 x Equipment costs
Installation = 50% x Total Equipment Costs
Total Installation Costs = (1.5) x Total Equipment Costs = 1.5 x 1.24 x Equipment Costs = 1.86 x Equipment Costs

- The SCR manufacturers also provided other pertinent information such as the SCR overall dimension and the number of catalyst layers needed to achieve 2 ppmv for a SRU/TG incinerator application.

- A contingency factor of 1.5 was used to cover any uncertainty in the estimated costs.

Summary of NEC's Approach

As previously described in Appendix F, NEC based their estimation of PWV on a manufacturer's detailed cost profile for a 3-bed SCR where 2 layers were designated for catalyst loading. NEC's preferred engineering design required 3 catalyst layers (4-bed design with one bed in reserve) to meet the 2 ppmv emissions level. As such, the ~~manufacturr's~~manufacturer's design was scaled upward based on additional catalyst volume and associated costs as well as adjustments to the space velocity. The revised design was then subjected to the cost assumptions stated in staff approach #2. PWV was estimated for the several feed rates to establish a distribution that was the basis for a power law cost curve. (See Addendum-1 to the staff report for NEC's analysis).

Summary

The staff and NEC approach to estimate the control costs differ. Addendum-1 of the Staff Report provides NEC's non-confidential "SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review". A major difference between the two assessments revolves around the selection of control equipment analyzed. The SCAQMD analysis included multiple control technologies while NEC analysis relied solely on SCR implementation where design options and costs were prorated for the SRU/TG applications. Additionally, costs associated with CEMS, ammonia storage tanks and heat exchangers account for differences between the initial staff and NEC cost estimates. Note that the different approaches do not have an impact on the list of equipment that meet the $50,000 per ton cost effectiveness threshold for inclusion in the calculation of potential BARCT emission reductions from SRU/TGUs.

A second major difference between the two assessments occurs in the costing methodology to estimate TIC and PWV. Staff's use of the EPA methodology with a 1.5 contingency factor markup to estimate PWV is lower than the combined bid conditioning, labor adjustment and 4.5 installation mark-up used by NEC. (It is important to note that separate discussions with refiners and their consultants indicated that a mark-up factor of 4.0 or greater may be more representative).

As stated in Appendix E, in their final assessment, staff revised its cost estimate to reflect the higher TIC to PWV cost factor proposed by NEC which resulted in closing the gap between the two analyses.

Appendix I - Comparative Analyses for Coke Calciners

This appendix provides a comparison of the NOx emissions control design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the Coke Calciner cost effectiveness calculation. Table I.1 summarizes the basic comparison. Variations in the equipment design, cost assumptions and TIC and PWV estimation methodology are provided in a side by side comparison for evaluation.

Table I.1 Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	NEC's Design
Proposed Control	LoTOx or UltraCat	LoTOx with modifications: taller or larger diameter scrubber, two vessels to enhance dry time, additional ozone usage and multiple ozone injection points
Target Emissions Limit	2 ppmv	5- 10 ppmv
Cost Basis	LoTOx TIC and UltraCat equipment costs provided by manufacturers	LoTOx equipment costs provided by manufacturers
	LoTOX PWV calculated by multiplying a 1.5 contingency factor to TIC and annual operating costs. UltraCat TIC estimated using the U.S. EPA 1.86 factor. PWA calculated by multiplying a 1.5 contingency factor to TIC and annual operating costs	TIC estimated as 1.35 factor applied to equipment cost to account for NEC proposed modifications. PWV calculated by multiplying a 3.44 contingency factor to TIC and annual operating costs

Summary of Staff's Approach

In order to collect cost data for all feasible control technologies, including LoTOx and UltraCat systems, staff sent the process information to the manufacturers, and the manufacturers provided equipment costs, annual operating costs, and foot print of the control devices. Staff used the approach in the EPA OAQPS Guidelines to estimate the Total Installed Costs (TIC = 1.86 x Equipment Costs.) This approach was used in the staff report of the 2005 RECLAIM rule amendment. Costs were increased by 50% to cover any uncertainty in the estimated TIC and annual operating costs.

Summary of NEC's Approach

NEC proposed 5 to 10 ppmv for BARCT. NEC used the costs provided to staff, and applied a factor of 4.67 to cover uncertainty in process development and installation costs. As a result, TIC = 4.67 x Equipment costs. Ultra-Cat was not considered a solution for the coke calciner.

Summary

Staff agrees that the coke calciner is a challenging application, and the BARCT level should be set at 10 ppmv as recommended by NEC. Addendum-1 of the Staff Report provides NEC's non-confidential "SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review". Staff also agrees that a factor higher than the EPA OAQPS's factor of 1.86 would be reasonable for the coke calciner because of the space congestion situation at the site. Staff revised the calculation and used a factor of 4.5 instead of 1.86 for both LoTOx and Ultra-Cat technologies.

Appendix J - Comparative Analyses for Turbine/Duct Burners

This appendix provides a comparison of the control design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the Turbine/ Duct Burner cost effectiveness calculation. Table J.1 summarizes the basic comparison. The cost assumptions for TIC and PWV estimation methodology are provided solely for the staff proposal since NEC recommendation was to add catalyst to achieve the 2 ppmv targeted emissions limit.

Table J.1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	**NEC's Design**
Control Devise Configuration	Install new SCR with Ammonia Slip Catalysts and/or add catalyst to existing SCRs	Add catalyst to existing SCRs
Cost Basis	Cost information provide by several sources: • SCR costs directly provided by Refineries 1 and 10; • Costs also provided by vendor for SCR • US EPA SCR cost estimate from literature • Cheng Low NOx technology	Costs information provided by vendor and Refinery 1
Cost Models	Cost curve relating PWV to MW	Cost curve relating PWV to MW

Appendix K – Co-Benefits of Energy Efficiency Projects

Table K.1 below summarizes NOx reductions that are expected to occur as co-benefits of energy efficiency projects undertaken by the refineries in the Basin from the California Air Resources Board (CARB)'s report "Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources – Refinery Sector Public Report, June 6, 2013.

CARB approved the Energy Efficiency and Co-Benefit Assessment of Large Industrial Facilities (EEA Regulation) on July 22, 2010. The regulation required the largest industrial sources in California to conduct a one-time assessment of fuel and energy consumption, and emissions of greenhouse gas, criteria pollutants, and toxic air contaminants. Affected facilities were also required to identify potential improvements in equipment, processes, or systems that could result in energy savings. http://www.arb.ca.gov/cc/energyaudits/energyaudits.htm#background.

CARB has a three-phase implementation plan to implement the EEA Regulation. Phase 1 was to develop the industrial sector public reports. From June 2013 to April 2015, CARB released five separate public reports compiling the information provided by the facilities subject to the EEA Regulation. The first report released in June 2013 was for the refinery sector. CARB is working on Phase 2 to develop the findings report, and Phase 3 to develop the Energy Efficiency Implementation Program. http://www.arb.ca.gov/cc/energyaudits/publicreports.htm.

CARB staff indicated that currently there was no requirement for the refineries to report the emissions stated in the public report released in June 2013 for inventory purposes. In addition, CARB had no process by which the inventory could be modified based on the estimates provided in the report. CARB did not know if the actual emission reductions would be different from the estimates in the report, and CARB had no plan to count these estimates as reductions to the current air quality. Thus, staff did not count the reductions in this proposal.

Table K. 1- Summary of Emission Reductions and Schedules of Energy Efficiency Projects

Facility	Completed/Ongoing Projects Completed Before 2011 (tpd)			Scheduled Projects After 2011 (tpd)	Under Investigation Projects After 2011 (tpd)		**Total (tpd)**	
	Range		Completion Date		Range		**Range**	
BP-Carson (Table II-4)	0.064	0.064	2009-11	0.014	0.019	0.019	**0.097**	**0.097**
Chevron El Segundo (Table II-9)	0.054	0.088	2007-11	0	0	0	**0.054**	**0.088**
Phillips66 Carson (Table II-17)	0	0.026	2008-11	0	0	0.013	**0**	**0.039**
Phillips66 Wilmington (Table II-21)	0	0	2009-11	0	0	0.013	**0**	**0.013**
ExxonMobil Torrance (Table II-29)	0.204	0.204	2008-11	0.036	0	0	**0.24**	**0.24**
Tesoro Los Angeles (Table II-37)	0.221	0.221	2009-11	0	0.049	0.049	**0.27**	**0.27**
Valero Wilmington (Table II-46)	0.056	0.056	2007-10	0	0	0	**0.056**	**0.056**
TOTAL (tpd)	0.6	0.7		0.1	0.1	0.1	**0.7**	**0.8**

Reference: Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources - Refinery Sector Public Report, June 6,

Note:

BP Carson identified 21 projects completed in the 2009-11 time frame (p.35)

Chevron identified 27 projects completed in the 2007-11 time frame (p. 38)

Phillips66 Carson identified 8 projects completed in the 2008-11 time frame (p. 44)

Phillips66 Wilmington identified 7 projects completed in the 2009-11 time frame that reduced 0 tpd NOx (p. 47)

ExxonMobil identified 25 projects completed in the 2008-2011 time frame (p.53)

Tesoro identified 11 projects completed in 2009-11 time frame (p.59)

Valero identified 13 projects completed in 2007-2010 time frame (p.65)

Appendix L – Survey Questionnaires for Refinery Sector

In June 2013, staff developed Survey Questionnaire to collect pertinent information for the NOx RECLAIM rule development. The Survey Questionnaire was sent to the 37 top emitting facilities and California Portland Cement Company which was the #1 NOx emission source in the Basin in 2008. The Survey Questionnaire for the refinery sector and the non-refinery sector are shown below.

South Coast Air Quality Management
2013 NOx RECLAIM
Survey Questionnaire for Refineries
(Due Date: July 12, 2013)

Facility Contact

1. Please provide the facility contact for this project:
   Name: ________________________________
   Title: ________________________________
   Phone Number: _________________________
   Email Address: _________________________

Top NOx Emitting Equipment or Processes

(* The attached list may contain the information requested)

2. * Please verify the attached list for the top 10 NOx emitting equipment and processes at your facility in Compliance Year 2011 and their emissions.

3. Please mark on the attached list the NOx control equipment installed **after the 2005 NOx RECLAIM amendment**

Boilers, Heaters, Furnaces, Kilns, Turbines, and Cogeneration Units (Major and Large Sources)

4. For each major and large combustion source at your facility, please verify the following information in the attached list, and provide information if the attached list does not contain this specific information:
   a. * Device description, Device ID, Process Name
   b. * Emissions in CY 2011 (tons per day)
   c. * Maximum unit rating (MMBTU/hr)
   d. * Type of fuel used
   e. Fuel usage rate and BTU content of fuel
   f. Flue gas flow rate (million dry standard cubic feet), temperature, oxygen and water content

g. Representative flue gas analysis and fuel gas analysis
h. NOx concentration in the exhaust flue gas (ppmv at 3% O_2 or ppmv at 15% O_2). Please attach a copy of the most current source test reports/results.
i. Allowable back pressure
j. * Control technology used (e.g. LNB, SCR, NOx scrubber)

5. For the control technology identified in item #4 above:
   a. Device description, Device ID
   b. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
   c. Design parameters (e.g. maximum flue gas flow rate, inlet and outlet ppmv, ammonia slip)
   d. If the control device is shared between multiple NOx emitting sources, please identify all other sources that are vented to this control device
   e. Dimension of the add-on NOx control device (e.g. length, width, height of the SCR, catalyst volume)
   f. Cost information (capital costs, installation costs, and annual operating costs)
   g. Installation date (e.g. July 2005)

6. Provide drawings that show location and distances between the major and large NOx sources at the facility.

Fluid Catalytic Cracking Units

7. If the facility currently uses NOx reduction catalysts, please provide:
   a. Manufacturer's name
   b. Usage rate (e.g. lbs of catalysts added per day)
   c. Flue gas flow rate, temperature, oxygen, water content and flue gas analysis
   d. NOx in the exhaust flue gas (ppmv at 3% O2). Please attach a copy of the source test results
   e. Cost information (annual operating costs)

8. If the facility uses add-on NOx control device, please provide:
   a. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
   b. Design parameters (max flue gas flow rate, temperature, oxygen, water content, flue gas analysis)
   c. NOx in the exhaust flue gas (ppmv at 3% O2). Please attach a copy of the source test report/results
   d. Dimension of the add-on NOx control device
   e. Cost information (capital costs, installation costs, and annual operating costs)
   f. Installation date (e.g. July 2005)

Reports Submitted Under the U.S. EPA Consent Decree

9. If the facility must install control technology to reduce the NOx emissions under an U.S. Environmental Protection Agency (EPA)'s consent decree, please provide the District a copy of the most recent reports/test results submitted to the EPA related to this consent decree.

Feasible Control Approach Including Energy Efficiency Project

10. List any feasible control approach that your facility plans to install, including replacement of the existing units with higher energy efficient units, to further reduce your facility's NOx emissions and green-house gases. Provide a brief description of the control approach, manufacturer's name, estimated emission reductions, and cost information.

If you have any questions, please contact either:
Minh Pham, P.E. (909) 396-2613, mpham@aqmd.gov, or
Gary Quinn, P.E. (909) 396-3121, gquinn@aqmd.gov

Please submit information via e-mail by July 12, 2013
to Minh Pham and Gary Quinn.
Thank you for participating in the Survey.

Part II – BARCT Analyses for Non-Refinery Sector

Part II contains the information related to the BARCT analyses for the non-refinery sector. Part II includes 7 Appendices from Appendix M to Appendix S that discuss 1) the NOx control technologies, 2) costs and cost effectiveness analyses for the NOx emitting sources at the top 27 non-refinery facilities, and 3) staff's review of the consultant's costs and cost effectiveness analyses. The Survey Questionnaires for non-refinery facilities are included in Appendix T.

Appendix M – Cement Kilns

Process Description

In the NOx RECLAIM program there is one facility that operates cement kilns. This facility, under normal operation, has typically been among the highest NOx emitters in the RECLAIM program. This facility produces gray cement from limestone, sand, shale, and clay raw materials. The raw materials are processed into a mix that is fed into a long, dry kiln that goes through pyroprocessing. Pyroprocessing transforms the fine raw mix into cement clinker through physical and chemical reactions inside the kiln. The facility operates two of these long, dry kilns that rotate slowly and are inclined at an angle. The raw materials are fed at the higher end of the kiln and proceed through it under the high heat of the combustion gases that are produced by the kiln burners at the lower end. Once the material exits the kiln, it is considered clinker and is cooled, and further processed (ground, milled) into cement. The combustion fuels used in these kilns include petroleum coke, natural gas and tire-derived fuel (TDF). The flue gases exiting the kilns are then ducted to individual waste heat boilers that operate a steam generator for electricity. After the waste heat boilers, the flue gases from each kiln go to a dedicated baghouse which separates the solid particulate. The resultant flue gases then exit from individual stacks.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged from the 2000 (Tier 1) Level, which is 2.73 pounds of NOx per ton of clinker produced.

Current Emission Inventory

There are two long, dry cement kilns located at the subject NOx RECLAIM facility. This facility was not in operation in compliance year 2011 due to decreased production and has not been in operation since. Therefore, for the purposes of calculating the BARCT reductions, the baseline emissions from the 2012 AQMP base year (2008) were used for the emission reduction determination and cost effectiveness calculation.

Table M. 1 - 2011 Emissions for Cement Kilns

Equipment Type (at Top 37 Facilities)	Number of Units	2008 Emissions (tpd)
Long, Dry Cement Kiln	2	1.61

Control Technology

Long, dry cement kilns have achieved NOx reductions to the 2000 (Tier 1) level by utilizing low NOx burners and mid kiln firing with tire-derived fuel (TDF). With TDF, whole tires are introduced at an inlet location about midway along the kiln's calcining zone. TDF lowers NOx emissions by lowering the flame temperatures and reducing thermal NOx with the introduction of a slower burning fuel.

The facility began testing one of the kilns with a selective non-catalytic reduction system (SNCR) before it ceased operation. This approach involves injecting ammonia directly into the kiln heating zone, where NOx reduction occurs without the utilization of a catalyst. With SNCR, the temperature window is critical for successful treatment of NOx. With a long, dry cement kiln, this is often difficult to achieve with the different temperature zones along its length and the necessity to inject the reagent mid-kiln. NOx treatment is easier to achieve on more modern preheater/precalcining kilns with SNCR since they are often shorter in length and the temperature window lies towards the exit of the kiln at the lower part of the preheater tower. This allows for readily feasible reagent introduction. The testing of the SNCR system at the facility yielded about a 30% NOx reduction. As applied to other kilns, SNCR is capable of achieving between a 30 and 50% NOx reduction. In the case of this facility, a 45% NOx reduction would result in meeting the New Source Performance Standard (NSPS) level of 1.5 pounds of NOx per ton of clinker produced. This emission level is equivalent to that of a new precalciner kiln using SNCR for NOx control.

After discussions with several vendors, there is more than one technology available for effective treatment of NOx from this source category beyond the Tier 1 level. To effectively achieve the most significant NOx reduction, selective catalytic reduction (SCR) is a proven technology that is well suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F. In cement applications, the inherently high particulate load of the flue gas stream has created problems in the past for catalysts. The dust can plug the catalyst matrix openings and can also mask active sites which results in a degradation of performance. This obstacle can be overcome by utilizing sootblowers which blow off the accumulated particulates at timed intervals from the catalyst surface. There have been several installations of SCR systems on cement kilns in Europe that can handle high dust loads in the flue gas. The installation at Monselice, Italy has been in operation since 2006 and the installation at Mergelstetten has been in operation since 2010. An

SCR has also been installed on a long, dry kiln in Joppa, Illinois. It has been operating since 2013 and can achieve an 80% NOx reduction.

For cement applications, an alternate technology is available primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. The flue gas is injected with ammonia that mixes with the gas and permeates across the ceramic filter wall. The filter material is embedded with catalyst which removes the NOx. Dry sorbent is injected in the flue gas to react with SOx. The resultant particulate, along with other particulate matter is captured at the outside of the filter walls.

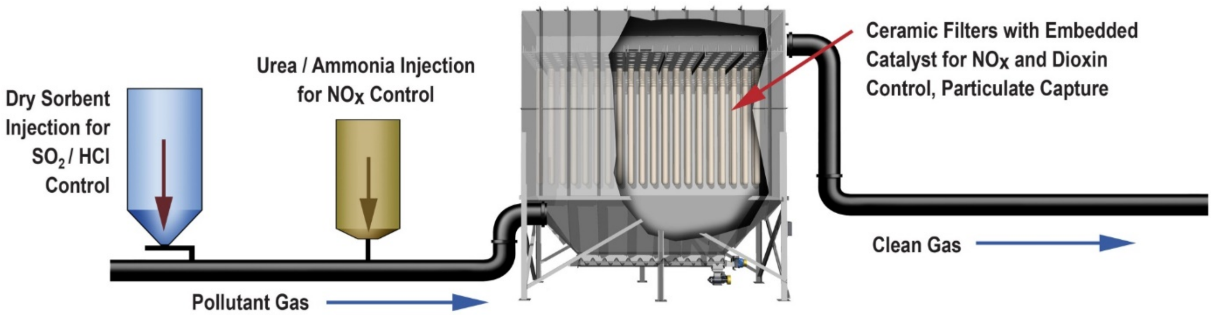

Figure M. 1 - Ultra Cat Ceramic Filter System

The accumulated solids on the filters are removed by a pulsed jet of air through the filter and the resultant solid waste is collected underneath the housing and is landfilled. This technology is guaranteed to achieve an 80% NOx reduction.

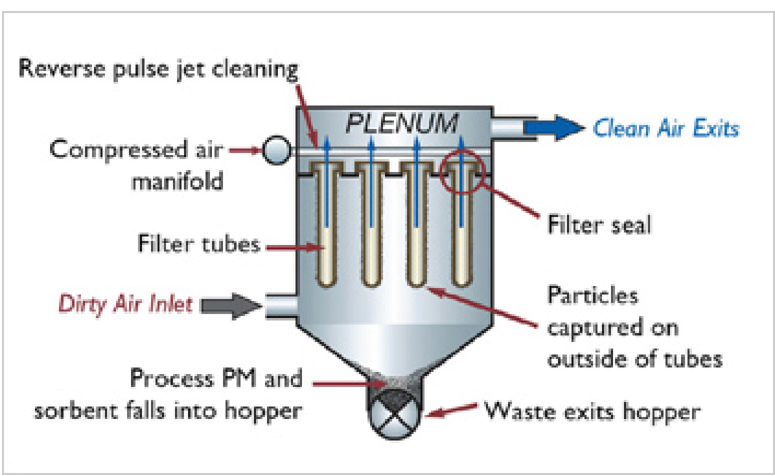

Figure M. 2 - Close-Up of Filter Housing and System Operation (~~Refernce~~Reference #2)

Another multi-pollutant control option for cement kilns is also possible that would reduce SOx and PM with a wet gas scrubber and treat NOx with SCR. A wet gas scrubber uses a liquid solution, typically caustic, as the absorbing agent for SO_2. The absorbed SO_2 is converted to sulfates and sulfites which are then captured in the liquid effluent treatment system where they are separated and then disposed. Solid particulates in the flue gas stream are removed by impaction with the liquid droplets inside the scrubber. The outlet flue gas stream is then processed by the SCR system for removal of NOx. Temperature control is extremely important for proper functioning of the pollutant control systems, primarily for SCR. The gas has to be hot enough after being processed by the scrubber for SCR treatment. This can be achieved by utilizing a heat exchanger ahead of the scrubber to reheat the gas to the proper temperature for SCR treatment. In this configuration, the scrubbing unit is installed ahead of the SCR for the purposes of removing SO_2 and preventing the formation of ammonium bisulfate (ABS). ABS formation is a result of sulfur compounds reacting with ammonia from the SCR system at a lower temperature below the dew point. ABS formation is reversible, and this involves heating the catalyst to evaporate it. When SO_2 is present in the flue gas stream, the minimum SCR process temperature is determined by the formation of ABS. With the removal of SO_2 from the flue gas stream by the scrubber, however, ABS formation is not an issue when operating the SCR system at the lower end of the normal temperature range.

Proposed BARCT level and Emission Reductions

SCAQMD command and control Rule 1112 set NOx limits for gray cement kilns. Last amended in 1986, the rule limits NOx emissions to 6.4 pounds per ton of clinker produced, averaged over any 30 consecutive day period. The 2005 NOx RECLAIM amendment proposed no new BARCT for cement kilns, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for cement kilns is 2.73 pounds of NOx per ton of clinker produced. When they were in operation, the two units in the NOx RECLAIM universe of facilities were compliant with the Tier 1 NOx emission level.

Based on vendor discussions, the proposed BARCT level for gray cement kilns is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system. This would result in an emission level of about 0.5 pounds of NOx per ton of clinker produced.

The emission reductions achieved from the two long, dry cement kilns, based on the 2008 compliance year baseline emissions, amount to 1.29 tons per day. This is the incremental reduction from the Tier 1 emission level.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs.

For an SCR installation on both kilns, the equipment costs include the SCR equipment, ductwork, steel, electrical, ammonia skid, sootblower air compressors, and insulation. The SCR system includes two layers of catalyst with a third layer for standby. A contingency value of 60% of the SCR equipment costs was estimated for the foundation civil work and other contingency. The SCR system for each kiln would be installed after the existing waste heat boiler and before the existing baghouse. This facility has specific plot space considerations that would require the installation of the SCR system between 5 and 30 yards from each waste heat boiler, depending on the kiln. The equipment would be placed on elevated platforms to allow for vehicle and/or railcar traffic underneath. There is no expected heat loss from the insulated ductwork. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were assigned a three year replacement interval.

For the Ultra Cat ceramic filter system, the equipment costs for both kilns include the emission control system, ammonia skid, booster fan, and engineering services, along with the installation. The annual operating costs include ammonia consumption, dry sorbent consumption, power consumption, labor, waste disposal, replacement filter costs. Since this facility is also a SOx source, dry sorbent injection for SOx removal will be required. This system would replace the existing baghouses at this facility.

The vendor-based equipment costs for the wet scrubber with heat exchanger and SCR for each kiln include the costs for the heat exchanger systems (ductwork, housing, dust collection hoppers), wet gas scrubber systems (venturi scrubber, pumps, structural steel, piping), and the SCR systems (2 layers of catalyst for each kiln, ductwork, ammonia skid, programmable logic control, sootblowers).

A contingency value of 60% of the equipment costs was estimated for the foundation and civil work, installation, and other contingency. The annual operating costs include ammonia consumption, catalyst replacement (3 year), caustic consumption, exhaust system fan power, scrubber pump power, and SCR dilution air fan and sootblower power. This system would replace the existing baghouses at this facility.

For all the scenarios, a present worth value (PWV) was calculated for the cement kilns using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

PWV = TIC + (15.622 x AC)

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This approach in calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table M. 2 - Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
Capital Costs ($)	14,950,000	30,000,000	31,938,838
Annual Costs ($)	1,220,500	1,000,000	4,818,537
Present Worth Value ($)	34,016,651	45,622,000	107,214,017
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	2,897	3,885	9,130
LCF Cost Effectiveness ($/ton)	4,635	6,216	14,609

To achieve an 80% NOx reduction, the cost effectiveness for cement kilns ranges from $2,900/ton to $9,100/ton ($4,600/ton to $14,600/ton, using LCF). Since the facility is also a SOx source, the calculated cost effectiveness combining NOx and SOx reductions equates to $3,300/ton for Vendor 2 and $7,600/ton for Vendor 3. This assumes a SOx reduction of 0.25 tons per day, as stated for the SOx RECLAIM amendment of 2010. All of the scenarios using the aforementioned NOx reduction technologies for flue gas treatment of cement kilns are considered cost effective.

Review of ETS's Analysis for Cement Kilns

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted a site visit at the facility to verify site specific considerations for the installation of control equipment.

For all the vendor installation estimates, a project scope contingency of 15% was applied to the total direct and indirect capital costs.

ETS concurs that there is sufficient plot space to install the control equipment for all three vendors and that an 80% NOx emission reduction is both feasible and cost effective.

Table M. 3 - ETS Revisions to Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)	Staff's Estimate(ETS's Estimate)
Capital Costs ($)	14,950,000 (17,192,500)	30,000,000 (34,500,000)	31,938,838 (36,729,664)
Annual Costs ($)*	1,220,500	1,000,000	4,818,537
Present Worth Value ($)	34,016,651 (36,259,151)	45,622,000 (50,122,000)	107,214,017 (112,004,843)
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	2,897 (3,088)	3,885 (4,268)	9,130 (9,538)
LCF Cost Effectiveness ($/ton)	4,635 (4,941)	6,216 (6,829)	14,609 (15,262)

* No revisions made by ETS

The facility made several comments regarding the BARCT analysis and staff conducted further research that resulted in a refinement of the cost analysis. Further communications with Vendor 1 revealed that the original estimate capital costs should have been doubled, as the previous costs were clarified as being for only one kiln. The facility had a concern over the temperatures at the exit of the waste heat boiler, before entering the control equipment. The facility provided an updated temperature which was 100 degrees below what had been provided previously and was below the normal operating temperature for normal SCR operation. To address this change, additional costs for reheating the flue gas were incorporated into the estimate, along with the natural gas costs to fuel the added duct burner. This updated system would utilize a natural gas-fired duct burner with a heat exchanger to reheat the gas approximately 100-150 degrees to enable the SCR catalyst to operate normally. The project contingency and other contingencies were adjusted to reflect the updated costs. The capital and operational costs for reheating the flue gas were applied to all three vendor estimates. In addition, operational costs were incorporated into the Vendor 3 estimate for wastewater treatment of the wet gas scrubber effluent. Furthermore, costs for powering new induced draft (ID) fans were also incorporated into the vendor estimates.

Table M. 4 - SCAQMD Revisions to Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
	ETS's Estimate (Staff's Estimate)	ETS's Estimate (Staff's Estimate)	ETS's Estimate (Staff's Estimate)
Capital Costs ($)	17,192,500 (37,812,000)	34,500,000 (38,400,000)	36,729,664 (42,166,606)
Annual Costs ($)*	1,220,500 (2,029,048)	1,000,000 (1,430,116)	4,818,537 (5,722,253)
Present Worth Value ($)	36,259,151 (69,509,788)	50,122,000 (60,741,272)	112,004,843 (151,559,636)
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	3,088 (5,919)	4,268 (5,172)	9,538 (11,203)
LCF Cost Effectiveness ($/ton)	4,941 (9,471)	6,829 (8,276)	15,262 (17,927)

To achieve the proposed BARCT level, the revised cost effectiveness for cement kilns ranges from $5,200/ton to $11,200/ton ($8,300/ton to $17,900/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of cement kilns are considered feasible and cost effective.

References for Cement Kilns

1. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda item 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

2. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

3. *Ammonium Bisulphate Inhibition of SCR Catalysts*. Thogersen, J.; Slabiak, T.; White, N. Haldor Topsoe.

4. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

5. *The Costs and Benefits of Selective Catalytic Reduction on Cement Kilns for Multi-Pollutant Control*. Armendariz, A. Department of Environmental and Civil Engineering, Southern Methodist University. February 11, 2008.

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7. *Evaluation of NOx Control Options for CalPortland's Colton, CA Cement Kilns*. Schreiber, R.; Russell, C. Schreiber Yonley & Associates, July 2, 2013.

8. *Arizona Regional Haze and Interstate Visibility Transport Federal Implementation Plan, Final Rule*. United States Environmental Protection Agency, Region 9. October 3, 2014; EPA-R09-OAR-2013-0588-0072.

9. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

Appendix N – Container Glass Melting Furnaces

Process Description

In the NOx RECLAIM program there is one facility among the top 37 NOx emitting facilities that operates container glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which is 1.2 pounds of NOx per ton of glass pulled.

Current Emission Inventory

There are two glass melting furnaces located at the subject NOx RECLAIM facility.

Table N. 1 - 2011 Emissions for Container Glass Melting Furnaces

Equipment Type	Number of Units	2011 Emissions (tpd)
Glass Melting Furnace (Container Glass)	2	0.30

Control Technology

Glass melting furnaces can achieve NOx reductions to the 2000 (Tier 1) level by utilizing oxy fuel firing. With oxy fuel firing, pure oxygen is used as the combustion reactant instead of nitrogen-laden ambient air. A higher temperature can be achieved for the batch melt based on the higher combustion efficiency in addition to achieving lower NOx emissions.

There is more than one technology available for effective treatment of NOx from this source category. To effectively achieve a significant NOx reduction, selective catalytic reduction (SCR) is a proven technology that is well suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

For glass melting applications, an alternate technology is available that has been achieved in practice, primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. Please refer to Appendix M for further details. This technology is guaranteed to achieve an 80% NOx reduction and has been installed or is under construction at 12 glass manufacturing locations worldwide.

Proposed BARCT level and Emission Reductions

SCAQMD command and control Rule 1117 set NOx limits for glass melting furnaces. Last amended in 1984, the rule limits NOx emissions to 4.0 pounds per ton of glass pulled, effective in 1992. The 2005 NOx RECLAIM amendment proposed no new BARCT for container glass melting furnaces, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for container glass melting furnaces is 1.2 pounds of NOx per ton of glass pulled. The two units in the NOx RECLAIM universe are currently compliant with the Tier 1 emission level.
Based on vendor discussions, the proposed BARCT level for container glass melting furnaces is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system. This would result in a NOx emission rate of 0.24 pounds per ton of glass pulled.

The emission reductions achieved from the two container glass melting furnaces, based on the reported value of emissions, amount to 0.24 tons per day. This is the incremental reduction from the Tier 1 emission level of 1.2 pounds of NOx per ton of glass pulled.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs and the costs provided by the facility.

For the Ultra Cat ceramic filter system, the equipment costs were scaled from an existing vendor-based installation quotation for a sodium silicate glass melting furnace. The equipment costs which include the emission control system, ammonia skid, and booster fan were scaled by the heat input rate to the 0.6 power based on general chemical engineering cost estimating practice. The installation costs were calculated to be 40% of the equipment costs. The cost of installation as well as the cost of engineering services was scaled by the heat input rate. The annual operating costs (also scaled by heat input rate) include ammonia consumption, dry sorbent consumption, power consumption, labor, waste disposal, replacement filter costs. Since this facility is also a SOx source, dry sorbent injection for SOx removal will be required. This system would replace the existing dry scrubbing system and electrostatic precipitators (ESPs) at this facility.

For an SCR installation, two scenarios were considered. In the first scenario, one SCR chamber would handle the exhaust streams from the three ESPs. At this facility, three ESPs handle the exhaust from the two glass melting furnaces in which one ESP is operated as a backup. In the second scenario, one SCR would handle the exhaust from each ESP, so there would be a total of three SCR systems installed.

The vendor-based costs for the first option include the engineering, fabrication and field installation of a single SCR chamber sized to handle the exhaust from both furnaces. The SCR system includes one layer of catalyst with extra space for a second layer, supporting structure, ammonia skid, and programmable logic control (PLC) system. A contingency value of 80% of the SCR equipment costs was estimated for the foundation and ductwork to and from the existing stacks. This facility has specific plot space considerations that would require the installation of the SCR system roughly 30 yards from the ESPs and roughly 15 yards back to the stacks. The equipment would be placed on an elevated platform above the existing rail line. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were conservatively assigned an annual replacement interval. In addition, a 20% contingency was added to the annual costs for freight and installation.

The vendor-based costs for the second option include the engineering, fabrication and field installation of three SCR chambers as described for the first option, each sized to handle the exhaust from one furnace. A contingency value of 150% of the SCR equipment costs was estimated for the foundation and ductwork to and from the existing stacks. The annual operating costs were also derived as described for the first option. This option also included an additional 20% contingency.

The facility also provided an estimate for the retrofitting of one furnace that was based on the EPA cost manual for SCR installations for NOx removal. To expand this singular case to address the remaining furnace, two scenarios were considered for this approach. The first option would include the installation of two SCR systems, each sized to handle the exhaust of one furnace, manifolded to the existing three ESPs. The second option would include the installation of three SCR systems, each sized to handle the exhaust of one furnace. Each SCR would handle the exhaust from each ESP. For each option, the costs for additional SCRs were calculated by multiplying the facility-provided costs for a single unit with number of additional units required for each of the two options. Also for each option, a 15% contingency factor was applied to the direct and indirect costs. The annual operating costs for each option include operations and maintenance labor/materials, ammonia consumption, power consumptions and catalyst costs. In addition, an indirect annual cost factor was added and was calculated to be the capital costs multiplied by the capital recovery factor (CRF) for a 25 year installation at a 4% interest rate.

For all the scenarios, a present worth value (PWV) was calculated for the glass melting furnaces using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This approach in calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table N. 2 - Cost Effectiveness for Container Glass Melting Furnaces

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.					
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.					
Vendor 3: SCR system installed post ESP using costs provided by facility per EPA cost Manual. NOx removal only. Option 1: two chambers. Option 2: three chambers.					
	Vendor 1	**Vendor 2 Option 1**	**Vendor 2 Option 2**	**Vendor 3 Option 1**	**Vendor 3 Option 2**
Capital Costs ($)	5,134,891	2,070,000	5,000,000	4,096,959	6,145,439
Annual Costs ($)	567,686	132,500	180,750	560,123	840,185
Present Worth Value ($)	14,003,287	4,139,195	7,823,677	12,847,207	19,270,811
Emission reductions (tpd)	0.24	0.24	0.24	0.24	0.24
DCF Cost Effectiveness ($/ton)	6,442	1,904	3,599	5,910	8,865
LCF Cost Effectiveness ($/ton)	10,308	3,047	5,759	9,457	14,186

To achieve an 80% reduction, the cost effectiveness for container glass melting furnace ranges from $1,900/ton to $8,900/ton ($3,000/ton to $14,200/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of container glass melting furnaces are considered cost effective.

Review of ETS's Analysis for Container Glass Melting Furnaces

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted a site visit at the facility to verify site specific considerations for the installation of control equipment.

For the Vendor 1 estimates, the calculation of the installation costs were adjusted to reflect 40% of the equipment costs, instead of being scaled from the base equipment case. Additionally, a contingency of 15% of the capital costs was applied to the overall estimate.

The Vendor 2 estimates were also adjusted by ETS for several items. Foundation and ductwork costs were added, as well as costs for new stacks for both options (single and three SCRs). Operation and labor costs were added to the annual costs for both options as well as costs for power consumption with the addition of a booster fan. The annual catalyst replacement costs were also adjusted for both options to reflect labor costs to replace the catalyst, along with recycling/disposal costs for spent catalyst. Additionally, a contingency of 15% of the capital costs was applied to the overall estimate.

The Vendor 3 cost estimates were not evaluated by ETS because they felt that the cost estimates provided by the equipment vendors with actual field experience with NOx removal would provide better estimates than the EPA cost manual method. Also, there was a disparity in the costs with the vendor estimates versus the EPA cost manual method because economics of scale were not taken into consideration, such as volume cost savings for multiple pieces of equipment.

Since the glass melting furnaces at this facility are also SOx emission sources, the flue gas has to be at a sufficiently high temperature to prevent ammonium bisulfate formation (ABS) while also removing NOx emissions effectively. ABS forms when the SO_3 in the flue gas reacts with the ammonia in the SCR system to produce ammonium salts. If the flue gas temperature is above the dew point for ABS, it will remain in the gaseous phase. However, if the temperature of the flue gas falls below the dew point for ABS, it will precipitate and deposit as a sticky substance on the SCR catalyst matrix. The result is reduced activity of the SCR catalyst and it will need to be reheated to reverse the process and reactivate it. Upon speaking with the equipment vendors, the SOx emissions from the glass melting furnaces would not result in ABS formation as long as the flue gas temperature remains as high as possible, any heat loss from the ductwork is mitigated, and there is not an overly lengthy duct run constructed to the SCR. The current stack temperatures at the facility are adequately above the ABS dew point and, therefore, there is no foreseeable issue with ABS deposition on the SCR catalyst.

ETS concurs that the NOx emission levels that are achievable is 80% for this source category. Achieving this level would be feasible with both technologies evaluated (i.e., ceramic filtration system or SCR). The plot considerations at this facility are complex, leaving little room for the installation of control equipment. The Vendor 1 system would involve removing the existing SOx dry scrubbers to create additional space and would need to be tied in presumably under a facility shutdown period. The Vendor 2 system would be complex as well, but ETS concurs that there is sufficient plot space for the installation of SCR.

To achieve the proposed BARCT level, the revised cost effectiveness for container glass melting furnaces ranges from $3,000/ton to $8,900/ton ($4,700/ton to $14,200/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of container glass melting furnaces are considered feasible and cost effective.

Table N. 3 - ETS Revisions to Cost Effectiveness for Container Glass Melting Furnaces

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.

Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.

Vendor 3: SCR system installed post ESP using costs provided by facility per EPA cost manual. NOx removal only. Option 1: two chambers. Option 2: three chambers.

	Vendor 1	**Vendor 2 Option 1**	**Vendor 2 Option 2**	**Vendor 3 Option 1**	**Vendor 3 Option 2**
	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)	Staff's Estimate*	Staff's Estimate*
Capital Costs ($)	5,134,891 (5,684,463)	2,070,000 (2,685,250)	5,000,000 (5,405,000)	4,096,959	6,145,439
Annual Costs ($)	567,686*	132,500 (240,909)	180,750 (360,753)	560,123	840,185
Present Worth Value ($)	14,003,287 (14,5~~2~~52,859)	4,139,195 (6,448,737)	7,823,677 (11,040,686)	12,847,207	19,270,811
Emission reductions (tpd)	0.24	0.24	0.24	0.24	0.24
DCF Cost Effectiveness ($/ton)	6,442 (6,695)	1,904 (2,967)	3,599 (5,079)	5,910	8,865
LCF Cost Effectiveness ($/ton)	10,308 (10,713)	3,047 (4,747)	5,759 (8,127)	9,457	14,186

*No revisions were made by ETS to the Vendor 3 costing or the indicated fields

References for Container Glass Melting Furnaces

1. *Alternative Control Techniques Document – NOx Emissions from Glass Manufacturing.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. June 1994; EPA-453/R-94-037.

2. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda item 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

3. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

4. *Ammonium Bisulphate Inhibition of SCR Catalysts*. Thogersen, J.; Slabiak, T.; White, N. Haldor Topsoe.

5. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

6. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

Appendix O– Sodium Silicate Furnace

Process Description

In the NOx RECLAIM program there is only one facility that produces sodium silicate. Sodium silicate is a substance either in a solid or liquid form that has a variety of industrial uses. It is manufactured by heating soda ash and sand in a melting furnace. The materials react with heat to produce sodium silicate and carbon dioxide.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which is 6.4 pounds of NOx per ton of glass pulled. This unit is considered a glass melting furnace, but since it processes sodium silicate, it is different than other types of glass melting furnaces such as container glass, flat glass, etc.

Current Emission Inventory

The single source sodium silicate melting furnace is a NOx major source.

Table O. 1 - 2011 Emissions for Sodium Silicate Furnace

Equipment Type	Number of Units	2011 Emissions (tpd)
Sodium Silicate Furnace	1	0.11

Control Technology

The raw material batch feed is delivered into the melting furnace which is fired by several natural gas-fired burners that melt the process feed. The flue gas then exits the furnace via a stack into the atmosphere. Combustion technology can often be employed to achieve some NOx reductions. Blower air staging, for example, can lower the temperature and result in lowering NOx emissions by around 15 to 20%.

To effectively achieve the largest reduction, however, selective catalytic reduction (SCR) is the technology that is best suited for significant flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

For glass melting applications, an alternate technology is available that has been achieved in practice, primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. Please refer to Appendix M for further descriptions. This technology is guaranteed to achieve an 80% NOx reduction.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1117 set limits for glass melting furnaces. Last amended in 1984, the rule limits NOx emissions to 4.0 pounds per ton of glass pulled, effective in 1992. The 2005 NOx RECLAIM amendment proposed no new BARCT for sodium silicate furnaces or other glass melting furnaces, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for sodium silicate furnaces is 6.4 pounds per ton of glass pulled.

The single unit in the NOx RECLAIM universe is currently compliant with the Tier 1 emission level. For sodium silicate furnaces based on vendor discussions, the proposed BARCT level for this source category is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system.

The emission reductions achieved from the sodium silicate furnace, based on the reported value of emissions, amounts to 0.09 tons per day. This is the incremental reduction from the Tier 1 emission level and is almost equivalent to the Tier 1 emission level for container glass melting furnaces (1.2 lbs/ton of glass pulled).

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs. There are no site-specific conditions that would increase the installation costs dramatically.

For SCR, the equipment and installation costs include the SCR chamber, one layer of catalyst with extra space for a second layer, supporting structure, ammonia skid, programmable logic control system (PLC), and engineering/fabrication. The foundation and ductwork was estimated to be 60% of the equipment and installation costs. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were conservatively assigned an annual replacement interval. In addition, a 20% contingency was added to the annual costs for freight and installation.

For the Ultra Cat ceramic filter system, the equipment costs include the emission control system, ammonia skid, booster fan, and engineering services. The installation costs were calculated to be 40% of the equipment costs. The annual operating costs include ammonia consumption, power consumption, labor, waste disposal and replacement filter costs. Since this facility is not a SOx source, dry sorbent injection for SOx removal would not be required.

For both technologies, a present worth value (PWV) was calculated for the sodium silicate furnace using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

PWV = TIC + (15.622 x AC)

A cost effectiveness value was then calculated for each technology using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table O. 2 - Cost Effectiveness for Sodium Silicate Furnace

Control Technology	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
SCR	1,600,000	76,315	2,792,193	0.09	3,470
Ultra Cat	1,986,161	166,016	4,579,663	0.09	5,691

The cost effectiveness for the sodium silicate furnace ranges from $3,500/ton to $5,700/ton ($5,600/ton to $9,100/ton, using LCF). This is to achieve an 80% NOx reduction. Both technologies for reducing NOx for the sodium silicate furnace are considered cost effective.

Review of ETS's Analysis for Sodium Silicate Furnace

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted an evaluation of the control technology and the costs for the installation of the control equipment.

For both vendor estimates, a contingency of 15% was applied the total direct and indirect capital costs. For the Vendor 2 estimate, the capital costs pertinent to SO_2 treatment were removed since this system would be removing NOx only.

To achieve the proposed BARCT level, the revised cost effectiveness for the sodium silicate furnace ranges from $3,800/ton to $5,700/ton ($6,000/ton to $9,200/ton, using LCF). Both scenarios using the aforementioned NOx reduction technologies for flue gas treatment of the sodium silicate furnace are considered feasible and cost effective.

Table O. 3 - ETS Revisions to Cost Effectiveness for Sodium Silicate Furnace

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.		
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.		
	Vendor 1	**Vendor 2**
	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)
Capital Costs ($)	1,600,000 (1,840,000)	1,986,161 (2,009,243)
Annual Costs ($)*	76,315	166,016
Present Worth Value ($)	2,792,193 (3,032,193)	4,579,663 (4,602,745)
Emission reductions (tpd)	0.09	0.09
DCF Cost Effectiveness ($/ton)	3,470 (3,768)	5,691 (5,719)
LCF Cost Effectiveness ($/ton)	5,552 (6,029)	9,106 (9,152)

*No revisions were made by ETS

References for Sodium Silicate Furnace

1. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

3. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

Appendix P – Metal Heat Treating Furnaces >150 MMBTU/hr

Process Description

In the NOx RECLAIM program there is one facility that operates these furnaces among the top 37 facilities. For the 2005 NOx RECLAIM amendment, a BARCT level of 45 ppm (0.055 lb/MMBTU) was established for metal heat treating furnaces.

Current Emission Inventory

Among the top 37 facilities in the NOx RECLAIM program, there are two furnaces above 150 MMBTU/hr that are metal heat treating furnaces for processing steel.

Table P. 1 - 2011 Emissions for Metal Heat Treating Furnaces >150 MMBTU/hr

Equipment Type (at Top 37 Facilities)	Number of Units	2011 Emissions (tpd)
Furnace >150 MMBTU/hr	2	0.49

Control Technology

As with all combustion sources, the type of burner used can affect the emissions. Some burners are lower NOx emitting than others. But for these types of furnaces, there are often dozens of burners that cumulatively require a high heat input. To achieve higher efficiency and to consume less fuel, recuperative and regenerative burners are used. These burners employ the principle of using preheated inlet air which is heated by the exhaust gases for more efficient combustion.

To effectively achieve a significant NOx reduction, however, selective catalytic reduction (SCR) is the technology that is best suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1147 set limits for metal heat treating furnaces at 60 ppm at 3% O_2 (0.073 lb/MMBTU). This rule was adopted in 2008 to address NOx emissions from miscellaneous sources. The 2005 NOx RECLAIM amendment proposed a BARCT level of 45 ppm at 3% O_2 (0.055 lb/MMBTU).

Based on vendor discussions for furnaces above 150 MMBTU/hr, the proposed BARCT level for this source category is an 80% reduction and the control technology to achieve the NOx reductions is SCR. An 80% NOx reduction from the 2005 BARCT level is equivalent to 9 ppm at 3% O_2.

The 2011 emissions adjusted to the 2005 BARCT level amount to 0.70 tons per day. The incremental reductions from each furnace from the 2005 BARCT level to the proposed BARCT level are 0.28 tons per day. One of the furnaces is already operating with an SCR system and is currently achieving around 20 ppm NOx. The source category incremental emission reductions achieved from the metal heat treating furnaces above 150 MMBTU/hr from the 2005 BARCT level amount to 0.56 tons per day.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs and the costs from an existing installation.

For SCR, the vendor-based equipment and installation costs include the SCR catalyst, reactor and ductwork, ammonia skid, dilution air fan, civil work, and installation. A contingency value of 200% of the SCR equipment costs was used to estimate the installation, foundation, civil work, and other construction uncertainties. The annual operating costs include ammonia consumption, catalyst replacement costs (2 year replacement interval), power consumption, and maintenance.

The existing equipment-based equipment costs include installation, SCR catalyst system, ammonia skid, and control system. A 60% contingency value of the equipment and installation cost was used to estimate the costs for other ductwork. The annual operating costs include ammonia consumption, catalyst replacement costs (2 year replacement interval), and maintenance.

For both scenario cases, a present worth value (PWV) was calculated for the metal heat treating furnaces using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table P. 2 - Cost Effectiveness for Furnaces > 150 MMBTU/hr

Control Technology	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
Vendor-based	2,800,152	440,631	9,683,684	0.28	3,800
Existing equipment-based	3,732,800	255,600	7,725,783	0.28	3,000

The cost effectiveness for furnaces above 150 MMBTU/hr ranges from $3,000/ton to $3,800/ton ($4,800/ton to $6,100/ton, using LCF). Achieving an 80% NOx reduction, SCR technology applied for reducing NOx for these furnaces is considered cost effective.

Review of ETS's Analysis for Metal Heat Treating Furnaces >150 MMBTU/hr

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. Based on staff's analysis and the review of technical information, ETS concurs that the NOx reduction level that can be achieved with SCR technology is 80%. No changes to the cost estimates were made.

References for Metal Heat Treating Furnaces >150 MMBTU/hr

1. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

Appendix Q – Non-Refinery, Non-~~Electrical~~ Electrcity Generating Facility Stationary Gas Turbines

Process Description

In the RECLAIM program, stationary gas turbines are used primarily to drive compressors or to generate power. In command and control, Rule 1134 limits the NOx emissions for all gaseous and liquid-fueled engines that are above 0.3 MW. Gas turbines operate either in simple cycle or combined cycle. Simple cycle units use the mechanical energy of shaft work that is transferred to and used by a gas compressor, for example, or to run an electrical generator to produce electricity. A combined cycle unit adds an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Combined cycle units are more efficient due to their use of two work cycles from the same shaft operation. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are not ~~electrical~~ electricity generating facility turbines (turbines that produce solely electric utility power). Some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam. In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which equates to 0.06 lb/MMBTU.

Current Emission Inventory

Among the top thirty seven non-~~electrical~~ electricity generating facility NOx emitting facilities in the RECLAIM universe, there are twenty gas turbines that are either major or large source units. Four of these units are currently utilizing some level of NOx control with selective catalytic reduction (SCR). The OCS turbines, which are fired on diesel or process gas, have the highest NOx emission concentrations in this source category. Six of these units are operated on an offshore oil drilling platform (outer continental shelf, or OCS).

Table Q. 1 - 2011 Emissions for RECLAIM Non-~~Electrical~~ Electrcity Generating Facility Gas Turbines

Turbine Type	Number of Units	2011 Emissions (tpd)
Total	20	1.92
Gas Compression	7	0.59
Cogeneration	6	0.75
Power Generation	1	0.09
OCS	6	0.49

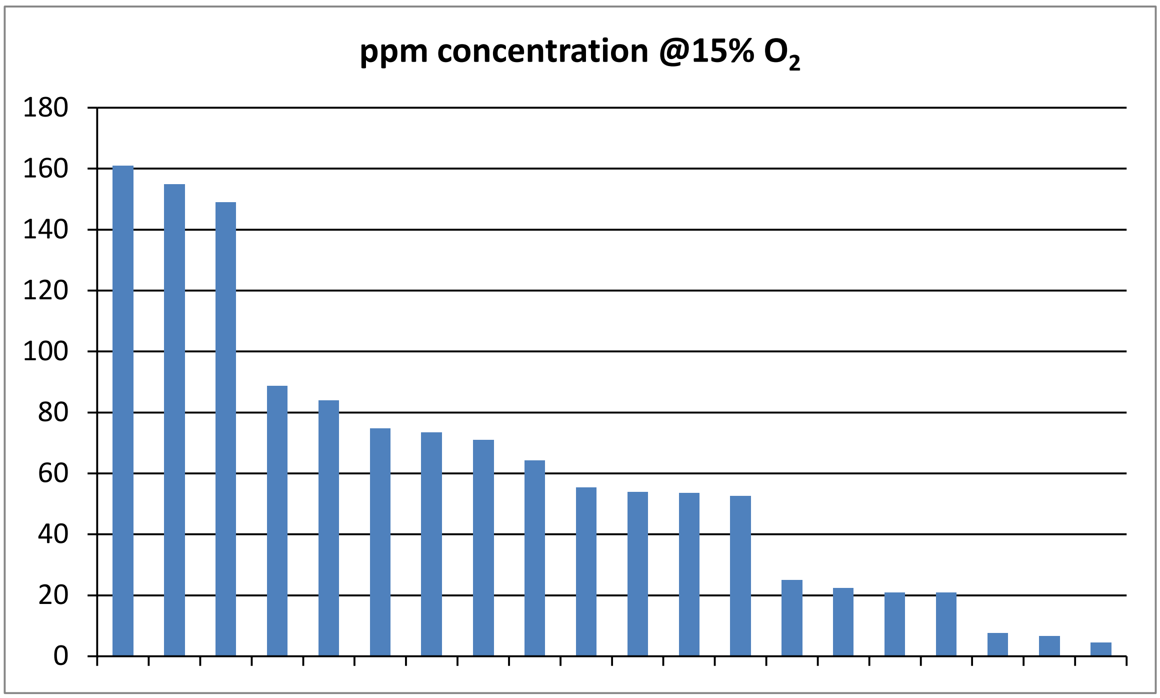


Figure Q. 1 - NOx Concentrations for Non-~~Electrical~~ Electrcity Generating Facility Gas Turbines at Top 37 Emitting Facilities

Control Technology

An uncontrolled unit will typically be emitting well over 100 ppm of NOx. There are several methods of NOx control for gas turbines, with differing levels of reduction.

Steam or water injection involves the introduction of either medium into the combustor flame zone to lower the flame temperature, thus reducing NOx formation. Typically, this will reduce NOx emissions up to 60%. Dry low emissions (DLE or DLN) is a type of dry control which involves a major modification to the turbine's combustion system. Unlike diffusion flames where the fuel and air mixes and combusts at the same time, DLE combustors are premixed, where the air and fuel mix first and then are combusted to produce a lower flame temperature. In addition, these systems operate under lean conditions, often with dual staged-combustion, further lowering NOx emissions. DLE technology can achieve NOx levels between around 10 and 45 ppm.

Selective catalytic reduction (SCR) is the most effective technology that can achieve ultra low NOx emissions. The technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1134 set limits for gas turbines for a range of sizes (ratings), with the limits varying between 9 and 25 ppm, corrected to 15% oxygen content. The 2005 NOx RECLAIM amendment proposed no new BARCT for gas turbines, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for natural gas and diesel fueled gas turbines in equivalent to 0.06 lb/MMBTU, which corresponds to approximately 17 ppm at 15% O_2. This reference limit can be higher, depending on the efficiency of the unit. The majority of the RECLAIM units in this source category have not installed the controls to meet the Tier 1 emission level.

For the non-~~electrical~~ electricity generating facility, non-refinery gas turbines in the top 37 facilities and based on vendor discussions and achieved in practice BACT installations, the proposed BARCT level for this source category is 2 ppm @15% O_2, and the control technology to achieve the NOx reductions is SCR. For units that are emitting less than 40 ppm NOx at 15% O2, a 2 ppm emission level is achievable with SCR only. In Figure Q.1, this would apply to the 7 units to the right of the chart. However, for those units emitting at 40 ppm, a 95 percent reduction is achievable. For the remainder of these units, a 95% reduction would achieve around 3 to 4 ppm. The power generating offshore units would achieve 8 ppm at a 95% reduction for their current emission level since they have the highest emissions. The offshore gas compression turbines can achieve 5 ppm at a 95% reduction. A 2 ppm level would be achievable for the units emitting above 40 ppm if these units would install either wet or dry combustion controls to comply with the Tier 1 emission level. The single power generating gas turbine that is non-OCS currently operates with an SCR system permitted at 5 ppm for NOx. Staff believes that a replacement of the catalyst system would be sufficient to meet the 2 ppm BARCT level. As a worst case, a present worth value was calculated from the same curve derived from existing refinery power generating units for a complete replacement of the SCR catalyst and equipment.

The emission reductions achieved from both subsets of units emitting above and below 40 ppm in the non-OCS sector are 1.04 tons per day. This is the incremental reduction from the Tier 1 level. The OCS units would add an additional 0.07 tons per day.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs. The vendor-supplied costs were for the SCR equipment only. This consists of the SCR housing, SCR catalyst, mixing ductwork, ammonia injection skid, PLC system, and CFD flow modeling.

Installation costs can vary due to the type of facility and any site-specific limitations. To derive a reasonable estimate, the installation costs were calculated to be double (or 200%) of the equipment costs. Since an SCR installation at an offshore facility could be more complicated than a typical onshore installation, the installation costs were calculated at four times the equipment costs to account for the unique site considerations for this type of installation. The annual operating costs include catalyst replacement (replacement interval of three years), ammonia consumption (19%), and electrical consumption.

A present worth value (PWV) was then calculated for each gas turbine using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$\text{PWV} = \text{TIC} + (15.622 \times \text{AC})$$

A cost effectiveness value was then calculated for each gas turbine using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = \text{PWV} / (\text{ER} \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (\text{TIC} \times \text{CRF}) + \text{AC} / (\text{ER} \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

The cost effectiveness for non-~~electrical~~ electricity generating facility, non-OCS gas turbines ranges from $4,700/ton to $35,900/ton ($7,500/ton to $57,500/ton, using LCF). This is to achieve a 95% reduction for those units emitting higher than 40 ppm and to achieve 2 ppm for those emitting lower than 40 ppm. For these gas turbines, the installation of SCR to treat NOx is cost effective. If the units emitting above 40 ppm install either wet or dry combustion controls to meet the Tier 1 emission level, then meeting 2 ppm is achievable.

The cost effectiveness for the offshore gas turbines ranges from $51,400/ton to $59,200/ton ($82,300/ton to $94,700/ton, using LCF). These figures reflect the power generating units achieving 8 ppm and the gas compression units meeting 5 ppm with SCR only. Since the cost effectiveness is above $50,000/ton and based on past rule makings, the OCS gas turbines are not considered cost effective in achieving the incremental NOx BARCT reductions from the Tier 1 level.

Table Q. 2 - Cost Effectiveness for Non-~~Electrical~~ Electrcity Generating Facility Gas Turbines

Unit	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
1	2,786,139	707,847	13,844,125	0.081	18,716
2	2,858,592	687,666	13,601,308	0.085	17,537
3	2,780,064	727,308	14,142,076	0.084	18,518
4	2,583,085	297,613	7,232,403	0.015	52,748
5	2,604,485	352,643	8,113,472	0.015	59,174
6	2,608,400	329,730	7,759,450	0.015	56,592
7	2,252,960	68,133	3,317,340	0.007	51,422
8	2,259,305	75,832	3,443,960	0.007	53,384
9	2,269,455	68,955	3,346,666	0.007	51,876
10	1,517,898	68,321	2,585,211	0.009	33,250
11	1,519,272	65,261	2,538,781	0.008	35,916
12	1,531,680	69,149	2,611,931	0.009	33,594
13	1,516,755	63,256	2,509,164	0.008	35,497
14	2,320,584	437,781	9,159,602	0.156	6,478
15	1,443,846	80,740	2,705,163	0.025	11,658
16	1,442,694	92,373	2,885,744	0.016	19,823
17	2,765,694	555,222	11,439,367	0.269	4,666
18	2,438,727	389,347	8,521,114	0.128	7,310
19	2,432,730	397,575	8,643,648	0.135	7,019
20	*	*	13,597,600	0.060	24,979

*PWV was determined from cost curve for refinery gas turbines (Figure C-5)

Review of ETS's Analysis for Metal Heat Treating Furnaces above 150 MMBTU/hr

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS concurs with the costing information and the conservative approach taken for calculating the costs for the possibly varied installations, given the site-specific aspects. ETS also concurs with the achievability of the reductions using SCR technology and no changes to the cost estimates were made.

References for Non-Refinery, Non-~~Electrical~~ Electrcity Generating Facility Stationary Gas Turbines

1. *Best Available Retrofit Control Technology Assessment – TXI Riverside Cement.* SCAQMD, August 8, 2008.

2. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

3. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

4. *Combustion and Fuels*. Solar Turbines Incorporated Presentation, Luke Cowell, June 6, 2012.

5. *Catalog of CHP Technologies: Combustion Turbines*. United States Environmental Protection Agency - Combined Heat and Power Partnership, March 2015.

6. *Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993; EPA-453/R-93-007.

7. *AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors*. United States Environmental Protection Agency, January 1995.

Appendix R – Non-Refinery Stationary Internal Combustion Engines

Process Description

Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate power. In command and control, Rule 1110.2 limits the NOx emissions for all gaseous and liquid-fueled engines that are above 50 brake horsepower (bhp). There are generally two types of engines, spark-ignited (SI) or compression ignited (CI) engines. SI engines ignite the air/fuel mixture with a spark while CI engines use the heat of compression to ignite the fuel that is injected into the combustion chamber.

Engines can run at either stoichiometrically rich or lean conditions, depending on the air to fuel ratio. Rich combustion corresponds to an air /fuel ratio that is fuel-rich while lean combustion corresponds to a fuel-lean air/fuel ratio. Small SI engines typically run as rich burn, but many larger units as well as CI engines operate under lean conditions. Usually, more air is inducted than is required for complete combustion and the resultant exhaust oxygen level is high (over 5%). Rich burn engines typically operate very close to stoichiometric conditions by drawing only the necessary air to combust the fuel. Spark-ignited engines are typically fired on gaseous fuels such as natural gas, while compression-ignited engines are fired on liquid fuels such as diesel.

In 2005, there was no new BARCT proposed for this source category. Consequently, the emission factor has remained unchanged since 2000 (Tier 1), which equates to about 57 ppm at 15% O_2 for natural gas-fired engines. During the 2008 amendment of Rule 1110.2, most stationary ICEs outside of RECLAIM (with the exception of biogas engines) were required to meet a NOx emission limit of 11 ppm at 15% O_2 by July 1, 2011.

Current Emission Inventory

Among the top thirty seven NOx emitting facilities in the RECLAIM universe, there are thirty one engines that are either major or large source units. Nine of these units are controlled with NSCR (non-selective catalytic reduction) as these engines are rich burn. Sixteen of these engines are SI lean burn units, while the remaining six are CI lean burn units. The CI lean burn units are all operated on an offshore oil drilling platform (outer continental shelf, or OCS). Six of the SI lean burn units are two-stroke engines (See Table 1). The engine sizes range from a little over 700 bhp to 5,500 bhp.

Table R. 1 - 2011 Emissions for Internal Combustion Engines at Top 37 Facilities

Engine Type (at Top 37 Facilities)	Number of engines	2011 emissions (tpd)
Lean Burn (Spark-Ignited)	16	0.34
Lean Burn (Compression Ignited), OCS	6	0.03
Rich Burn (Spark-Ignited)	9	0.02
~~Electrical~~ <u>Electrcity</u> Generating Facility (2 stroke)	6	0.18
Total	37	0.56

There are also 6 additional ICEs that belong to a power producing facility, and the combined emissions from these engines were 0.18 tons per day in 2011. These engines are 2-stroke engines that are fired on diesel fuel due to the lack of access to natural gas.

CI engines, which are fired on diesel, have the highest NOx emission concentrations in this source category. 2-stroke SI engines have higher NOx emissions than 4-stroke SI engines since the higher efficiencies in 2-stroke engines translate to a hotter combustion temperature that can create more NOx.

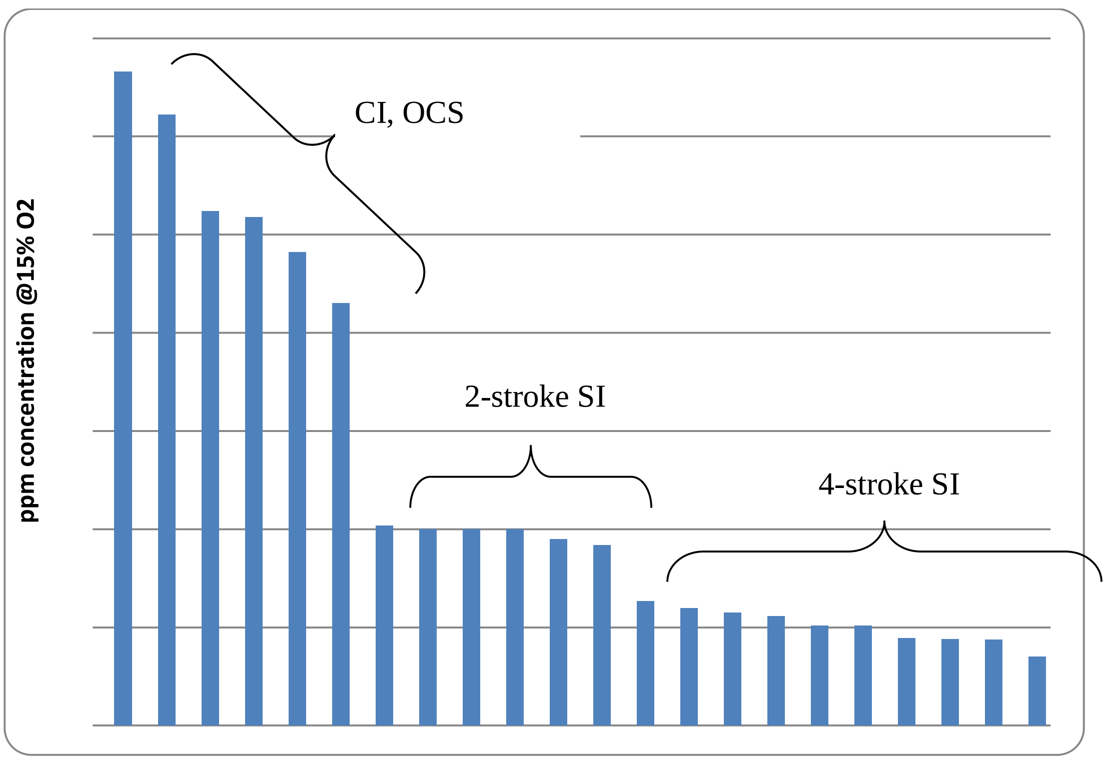


Figure R. 1 - NOx concentrations for Lean Burn ICEs at Top 37 Emitting Facilities

Control Technology

The flue gas from rich burn engines is typically very low in excess oxygen. This enables NOx reduction to take place via Non-Selective Catalytic Reduction technology (NSCR), which is inexpensive, readily installed, and simultaneously removes NOx, CO, and VOC. NSCR (or three-way) catalysts have been commercially available for many years and can achieve NOx removal efficiencies of over 90 percent. The catalyst reduces NOx to nitrogen and oxygen in the presence of CO and VOC, while simultaneously oxidizing CO and VOC to form carbon dioxide and water. Precise air/fuel ratio control is required since the catalytic reactions must occur within a narrow air/fuel ratio band.

With lean burn exhaust the higher oxygen content does not allow effective removal of NOx with NSCR. On this basis, CO and VOC will have a preferential reaction with the oxygen instead of the NOx. In this case, Selective Catalytic Reduction (SCR) is the technology of choice. Oxygen is an essential ingredient in the SCR reactions and the excess oxygen in the exhaust gas provides this. Ammonia (or urea) is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of a catalyst to produce nitrogen and water vapor. The catalyst material is typically a base metal catalyst such as titanium dioxide or vanadium pentoxide, and operates within a temperature range of 450 to 850 F.

Proposed BARCT level and Emission Reductions

The 2008 amendment to Rule 1110.2 established a NOx emission level of 11 ppm @15% O_2 for most IC engines. The technology identified for rich burn engines was NSCR while the technology identified for lean burn engines was SCR. The effective date for complying with the final rule limit has been in effect for over four years. NSCR is feasible for rich burn engines and SCR is feasible for both two-stroke and four-stroke lean-burn engines.

The 2005 RECLAIM amendment proposed no new BARCT for IC engines, so these units have been only required to meet the Year 2000 Tier 1 emission level. For the non-~~electrical~~ electricity generating facility engines in the top 37 emitting facilities, the proposed BARCT level is 11 ppm @15% O_2. The rich burn engines in this category have all been retrofitted with NSCR and most of them meet the proposed BARCT level. These three way catalysts were installed to control CO and VOC for compliance with Rule 1110.2 requirements by July 1, 2011, since these pollutants are not governed under RECLAIM rules. There is an added benefit with three way catalysts because they also control NOx and this has resulted in emission reductions for these engines. For lean burn engines, however, the control technology to achieve the NOx reductions is SCR. If all the non-OCS engines in this category were to achieve the proposed BARCT level, the emission reductions from the Tier 1 level would be 0.84 tons per day. There is a portion of this reduction that is attributed to the rich burn engines and it amounts to 0.07 ton per day. Recent source tests indicate that the majority of these engines are already meeting the proposed BARCT level of 11 ppm. It is assumed that these engines will continue to meet the 11 ppm emission level.

The ~~electrical~~ electricity generating facility engines, since they are 2-stroke diesel engines, are more difficult in terms of reducing NOx emissions. These engines are isolated and there is no other fuel backup. The unique nature of these engines provides a challenge with regards to very low allowable backpressures, which makes SCR an inflexible treatment option. Therefore, there is no new proposed BARCT for ~~electrical~~ electricity generating facility ICEs.

The OCS engines in this category will not be subject to the new BARCT because the engines at offshore platforms run rig generators that are often variable in load. SCR systems need a more constant load so that the proper operating temperatures can be sustained for effective NOx removal.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using both vendor-supplied costs along with installation costs from an existing SCR installation on a lean-burn engine. The vendor-supplied costs were for the SCR equipment only. This consists of the SCR housing, SCR catalyst, mixing ductwork, expansion joint, urea injection skid (control system, pump, dosing unit), and an air compression/drying system.

Installation costs can vary due to the type of facility and any site-specific limitations. To derive a reasonable estimate, the costs from an achieved in practice SCR installation on a lean-burning engine were used. This engine is located at Orange County Sanitation District (OCSD), is fired on natural gas and digester gas, and is retrofitted with an oxidation catalyst and SCR. It was installed in 2009 and has been consistently been meeting the 11 ppm NOx limit of Rule 1110.2. The catalyst system had to be placed on an externally constructed platform because of the site constraints inside the engine building. These additional costs have been included as part of this analysis in anticipation of any supplemental support structures necessary to accommodate the SCR system. The 2009 dollar figures for the OCSD installation were raised to 2013 dollar values using the Marshall & Swift Index inflation factor. The installation costs for all the affected engines were scaled by horsepower based on the costs for this installation at OCSD.

The annual operating costs include catalyst replacement, reagent consumption, reagent delivery system maintenance, and electrical consumption. The annual costs for the OCSD installation assume a 3 year SCR catalyst replacement interval and were scaled for the engines in this source category by engine horsepower. For two-stroke engines, a very conservative replacement interval of one year was selected due to the potentially more contaminated exhaust gas stream (ash, soot) from this type of engine.

A present worth value (PWV) was then calculated for each engine using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

PWV = TIC + (15.622 x AC)

A cost effectiveness value was then calculated for each engine using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table R. 2 - Cost Effectiveness for Lean-Burn, Non-OCS ICEs

Unit	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
1	890,182	36,625	1,462,338	0.036	4,500
2	890,182	36,625	1,462,338	0.033	4,900
3	890,182	36,625	1,462,338	0.033	4,800
4	890,182	36,625	1,462,338	0.034	4,700
5	890,182	36,625	1,462,338	0.035	4,600
6	1,386,291	82,640	2,677,289	0.043	6,900
7	485,628	25,696	887,048	0.019	5,000
8	485,628	25,696	887,048	0.019	5,000
9	1,307,772	77,475	2,518,084	0.038	7,300
10	485,628	25,696	887,048	0.019	5,100
11	1,307,772	77,475	2,518,084	0.037	7,500
12	2,319,249	100,719	3,892,680	0.084	5,000
13	2,319,249	100,719	3,892,680	0.084	5,000
14	2,319,249	100,719	3,892,680	0.085	5,000
15	2,319,249	100,719	3,892,680	0.083	5,200
16	2,319,249	100,719	3,892,680	0.084	5,000

The cost effectiveness for non-~~electrical~~ electricity generating facility IC engines ranges from \$4,500/ton to \$7,500/ton (\$7,200/ton to \$12,000/ton, using LCF). For these engines, the installation of SCR to treat NOx is cost effective.

Review of ETS's Analysis for Non-Refinery Stationary Internal Combustion Engines

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS concurs with the costing information and the conservative approach taken for calculating the costs for the possibly varied installations, given the site-specific aspects. ETS also concurs with the achievability of the reductions using SCR technology and no changes to the cost estimates were made.

References for Non-Refinery Stationary Internal Combustion Engines

1. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

3. *AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors*. United States Environmental Protection Agency, January 1995.

4. *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993; EPA-453/R-93-032.

5. *Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology*. SCAQMD Contract #10114, Orange County Sanitation District, July 2011.

Appendix S – Non-Refinery Boilers >40 MMBTU/hr

In the top 37 emitting facilities, there are four boilers that are above 40 MMBTU/hr. They range between 49 and 247.3 MMBTU/hr. The 2005 BARCT level for these units was 9 ppm at 3% O_2. The incremental NOx reduction going from 9 ppm to a proposed BARCT level of 2 ppm would be 0.01 tons per day.

SCR would be the technology of choice for achieving NOx reductions for larger boilers. The costs for retrofitting these units were estimated from the ETS-adjusted vendor quotes for a similar sized installation for the sodium silicate furnace. The present worth value for the installation in on a 56.6 MMBTU/hr combustion furnace is $4,602,745. The present worth value for the largest unit was calculated from the cost curve developed for refinery boilers and heaters (Figure B-3).

The DCF cost effectiveness for all of the four units were calculated to be above $150,000 per ton of NOx. Therefore, retrofitting with SCR would not be cost effective. ETS concurs that the costs for installing SCR would not be cost effective for this source category.

Table S. 1 - Cost Effectiveness for Non-Refinery Boilers >40 MMBTU/hr

Unit	Rating (MMBTU/hr)	PWV ($)	Incremental Emission Reductions (tpd)	DCF Cost Effectiveness ($/ton)
1	57	4,602,745	0.003	182,107
2	62.5	4,602,745	0.003	153,938
3	49	4,602,745	0.0001	6,447,425
4	247.3	13,527,310	0.004	380,515

Appendix T – Survey Questionnaires for Non-Refinery Sector

South Coast Air Quality Management
2013 NOx RECLAIM
Survey Questionnaire for Non-Refineries
(Due Date: July 12, 2013)

Facility Contact

1. Please provide the facility contact for this project:
   Name: ______________________________
   Title: ______________________________
   Phone Number: ________________________
   Email Address: ________________________

Top NOx Emitting Equipment or Processes

(* The attached list may contain the information requested)

2. * Please verify the attached list for the top 10 NOx emitting equipment and processes at your facility in Compliance Year 2011 and their emissions.

3. Please mark on the attached list the NOx control equipment installed **after the 2005 NOx RECLAIM amendment**

Boilers, Heaters, Furnaces, Kilns, Turbines, and Cogeneration Units (Major and Large Sources)

4. For each major and large combustion source at your facility, please verify the following information in the attached list, and provide information if the attached list does not contain this specific information:
   k. * Device description, Device ID, Process Name
   l. * Emissions in CY 2011 (tons per day)
   m. * Maximum unit rating (MMBTU/hr)
   n. * Type of fuel used
   o. Fuel usage rate and BTU content of fuel
   p. Flue gas flow rate (million dry standard cubic feet), temperature, oxygen and water content
   q. Representative flue gas analysis and fuel gas analysis
   r. NOx concentration in the exhaust flue gas (ppmv at 3% O_2 or ppmv at 15% O_2). Please attach a copy of the most current source test reports/results.
   s. Allowable back pressure
   t. * Control technology used (e.g. LNB, SCR, NOx scrubber)

5. For the control technology identified in item #4 above:

h. Device description, Device ID
i. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
j. Design parameters (e.g. maximum flue gas flow rate, inlet and outlet ppmv, ammonia slip)
k. If the control device is shared between multiple NOx emitting sources, please identify all other sources that are vented to this control device
l. Dimension of the add-on NOx control device (e.g. length, width, height of the SCR, catalyst volume)
m. Cost information (capital costs, installation costs, and annual operating costs)
n. Installation date (e.g. July 2005)

6. Provide drawings that show location and distances between the major and large NOx sources at the facility.

Reports Submitted Under the U.S. EPA Consent Decree

7. If the facility must install control technology to reduce the NOx emissions under an U.S. Environmental Protection Agency (EPA)'s consent decree, please provide the District a copy of the most recent reports/test results submitted to the EPA related to this consent decree.

Feasible Control Approach Including Energy Efficiency Project

8. List any feasible control approach that your facility plans to install, including replacement of the existing units with higher energy efficient units, to further reduce your facility's NOx emissions and green-house gases. Provide a brief description of the control approach, manufacturer's name, estimated emission reductions, and cost information.

If you have any questions, please contact either:
Kevin Orellana (909) 396-3492, korellana@aqmd.gov, or
Gary Quinn, P.E. (909) 396-3121, gquinn@aqmd.gov

Please submit information via e-mail by July 12, 2013
to Kevin Orellana and Gary Quinn.
Thank you for participating in the Survey.

Part III – RTC Reduction Approaches

Part III contains information pertinent to the RTC reductions estimation. Part III contains three appendices: Appendix U contains a discussion on staff's approaches and calculation to determine the RTC reductions based on the 2015 BARCT levels assessed in Part I for the refinery sector and Part II for the non-refinery sector. Staff's calculation were also based on the 2011 audited NOx emissions for all NOx RECLAIM facilities except ~~electrical~~ electricity generating facilities. For ~~electrical~~ electricity generating facilities, staff used the 2012 baseline emissions. Appendix V contains the 2011 audited emissions, and Appendix W contains the 2012 baseline emissions for ~~electrical~~ electricity generating facilities.

Appendix U – Staff's Proposal and CEQA Alternatives

Staff has considered several options to determine the most appropriate RTC shave distribution to effect emission reductions that will protect the environment, satisfy the state and federal CAA requirements, and satisfy AQMP commitments, while concurrently providing for growth and safeguards for the continued functioning of the RECLAIM program. The RTC reductions with the application of BARCT total 14.79 tons per day. However, an adjustment is proposed to the total RTC reductions to account for issues that have been raised by stakeholders regarding the BARCT analysis. These issues primarily focused on the potential uncertainties of the control costs for refinery boilers and heaters and the reliability and consistency in maintaining controlled NOx concentrations for the coke calcining unit. With these adjustments, the RTC reduction that would be applied for the shave approaches would total 14 tons per day by 2023.

The shave proposals under consideration affect four major groups within the NOx RECLAIM universe:

- Major Refineries and Investors
- Top 90% of RTC Holders
- Others (Bottom 10 percent of RTC Holders)

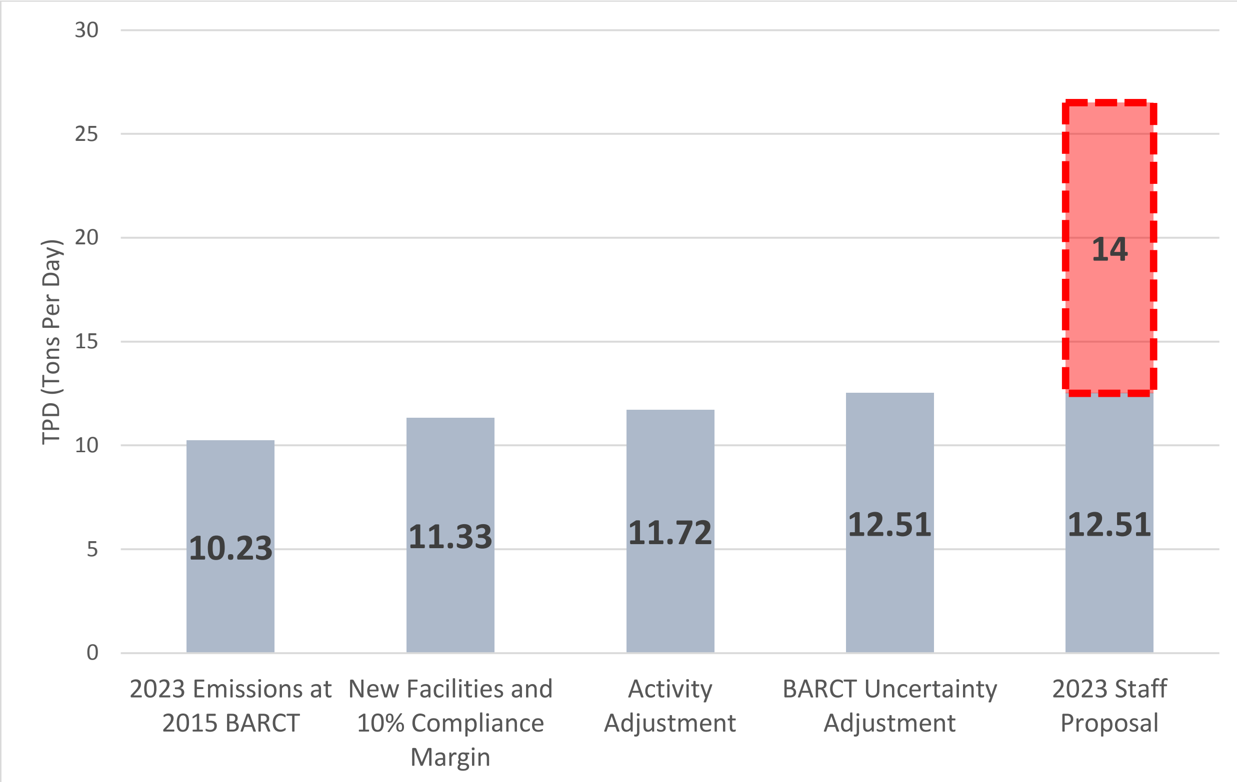
The bottom 10 percent of RTC holders would be exempted from an RTC reduction under the staff proposal. It should be noted that the newer ~~electrical~~ electricity generating facilities among the top 90% of RTC are subject to NSR holding requirements for their equipment, which is mostly at BACT. Staff is proposing a Regional NSR Holding Account for these facilities in order provide some relief given their ongoing NSR obligations of holding RTCs at the equipment's potential to emit level at the beginning of each compliance year.

Staff Proposal

Calculation of Remaining Emissions

The remaining emissions are determined by summing the calculated remaining emissions in 2023 with economic growth factors applied and with BARCT applied for both the refinery and non-refinery sectors (Tables 5.1 and 5.2). The remaining emissions total 10.23 tons per day. Emissions accounting for new RECLAIM facilities since the 2011 base year are added and a 10% compliance margin is applied, so the remaining emissions become 11.33 tons per day. Next, an activity adjustment, accounting for atypical operation conditions in 2011, is applied which results in 11.72 tons per day remaining. Lastly, a BARCT uncertainty adjustment is applied to account for uncertainties in the analysis. After all the adjustments, the total remaining emissions are 12.51 tons per day. This is equivalent to a 14 ton per day reduction from the allocation cap of 26.51 tons per day. Figure U.1 illustrates the adjustments and the total RTC reduction.

Figure U.1 – 2023 Adjustments and Allocation Target



The staff proposal for the shave would affect the top 90 percent of RTC holders, which includes major refinery facilities. Investors would also be shaved at this level. Refineries and Investors are designated as Category A facilities in Table U.1. Non-major refinery facilities in the top 90% of RTC holders and ~~electrical~~ electricity generating facilities among the top 90% of RTC holders would be included in the shave as Category B1 and B2 facilities, respectively. The reductions for the facilities subject to the shave would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 66 percent. For non-major refineries and all other facilities among the top 90 percent of RTC holders, the RTC holdings would be shaved by 49 percent. See Tables U.1 and U.2.

Table U.1 - List of 56 Affected Facilities Plus Investors

HOLDINGS AS SEPTEMBER 22, 2015

USING TOP 90% RTC HOLDINGS LIST FROM 3/20/15

ID	Name	Category
148553	VERNON CITY, LIGHT & POWER DEPARTMENT	A
700144	OLDUVAI GORGE, LLC	A
700161	KOCH SUPPLY & TRADING, LP	A
700084	SHELL NORTH AMERICA (US), L.P.	A
16352	SO CAL EDISON CO	A
158300	CITY OF ONTARIO	A
710	TEXACO EXPLORATION & PRODUCTION INC.	A
700050	KEN BARKER	A
800042	ECO PETR INC (EIS USE ONLY)	A
101337	NATIONAL OFFSETS	A
800253	UNION CARBIDE CORP	A
169514	TITAN TERMINAL AND TRANSPORT INC	A
700170	ABATEMENT CAPITAL LLC	A
700175	TWIN EAGLE RESOURCE MANAGEMENT LLC	A
700177	GREY EPOCH LLC	A
800030	CHEVRON PRODUCTS CO.	A
800089	EXXONMOBIL OIL CORPORATION	A
174655	TESORO REFINING & MARKETING CO, LLC	A
800436	TESORO REFINING AND MARKETING CO, LLC	A
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	A
800026	ULTRAMAR INC	A
166073	BETA OFFSHORE	B1
800128	SO CAL GAS CO	B1
46268	CALIFORNIA STEEL INDUSTRIES INC	B1
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	A
174591	TESORO REFINING & MARKETING CO LLC, CAL	A
169754	OXY USA INC	B1
7427	OWENS-BROCKWAY GLASS CONTAINER INC	B1
18931	TAMCO	B1
800183	PARAMOUNT PETR CORP	B1
43201	SNOW SUMMIT INC	B1
172005	NEW- INDY ONTARIO, LLC	B1
800189	DISNEYLAND RESORT	B1
156741	HARBOR COGENERATION CO, LLC	B1
151798	TESORO REFINING AND MARKETING CO, LLC	A
11435	PQ CORPORATION	B1
4242	SAN DIEGO GAS & ELECTRIC	B1

17953	PACIFIC CLAY PRODUCTS INC	B1
800127	SO CAL GAS CO	B1
180367	LINN OPERATING, INC	B1
124838	EXIDE TECHNOLOGIES	B1
800181	CALIFORNIA PORTLAND CEMENT CO	B1
51620	WHEELABRATOR NORWALK ENERGY CO INC	B1
5973	SO CAL GAS CO	B1
3968	TABC, INC	B1
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	B1
178639	ECO SERVICES OPERATIONS LLC	B1
800153	US GOVT, NAVY DEPT LB SHIPYARD	B1
8547	QUEMETCO INC	B1
1073	BORAL ROOFING LLC	B1
115394	AES ALAMITOS, LLC	B2
115663	EL SEGUNDO POWER, LLC	B2
800074	LA CITY, DWP HAYNES GENERATING STATION	B2
800075	LA CITY, DWP SCATTERGOOD GENERATING STN	B2
115536	AES REDONDO BEACH, LLC	B2
160437	SOUTHERN CALIFORNIA EDISON	B2
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	B2
152707	CPV SENTINEL LLC	B2
115389	AES HUNTINGTON BEACH, LLC	B2
4477	SO CAL EDISON CO	B2
146536	WALNUT CREEK ENERGY, LLC	B2
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	B2
115314	LONG BEACH GENERATION, LLC	B2
153992	CANYON POWER PLANT	B2
800193	LA CITY, DWP VALLEY GENERATING STATION	B2
25638	BURBANK CITY, BURBANK WATER & POWER	B2
800168	PASADENA CITY, DWP	B2
155474	BICENT (CALIFORNIA) MALBURG LLC	B2
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	B2
129816	INLAND EMPIRE ENERGY CENTER, LLC	B2
700126	GENERAL ELECTRIC COMPANY	B2

COUNTS

Category	Description	
A	Major Refineries	9
A	Investors (Counted as 1 Facility)	1
B1	Top 90% Holder, Non-~~Electrical~~ Electrcity Generating Facilities	26
B2	Top 90% Holder, ~~Electrical~~ Electrcity Generating Facilities	21
TOTAL		57

Table U.2 - RTC Reduction Calculation

Refinery Reductions Beyond 2005 BARCT, tpd	6.00
Non-Refinery Reductions Beyond 2005 BARCT, tpd	2.77
Total, tpd	8.77

Refinery Contribution to Emission Reduction (6.00 / 8.77 x 100)	68%
Non-Refinery Contribution to Emission Reduction (2.77 / 8.77 x 100)	32%

Total RTC Allocation in 2023	26.51
Remaining 2023 Emissions After BARCT and Growth	11.72
Minus BARCT Uncertainty Adjustment	0.79
Total RTC Reduction (26.51 - 11.72 - 0.79)	14

Weighted Reduction for Refinery (14.00 x 68%)	9.58
Weighted Reduction for Non-Refinery (14.00 x 32%)	4.42
Total Reduction	14

Major Refinery + Investor Holdings for Top 90%	14.57
Non-Major Facility Holdings + All ~~Electrical~~ Electrcity Generating Facility Holdings for Top 90%	9.09
RTC Holdings for Top 90% of Holders, Including Investors (14.57 + 9.19)	23.66

Remaining Major Refinery + Investor RTC Holdings (14.57 - 9.58)	4.99
% Shave to this Sub-Universe (9.58 / 14.57) x 100	66%

Remaining Non-Refinery RTC Holdings (9.09 - 4.42)	4.67
% Shave to this Sub-Universe (4.42 / 9.09) x 100	49%

RTC Reductions = Current Holdings (26.51 tpd) – Remaining Emissions in 2023 (11.72 tpd) = 14.79 tpd
Total RTC Reductions = 14.79 tpd – (BARCT adjustment of 0.79 tpd) = 14 tpd

CEQA Alternatives

CEQA Alternative 1: This approach would be an across the board RTC reduction and would affect all RECLAIM facilities and investors. The RTC holdings would be shaved by 53 percent overall.

CEQA Alternative 2: This approach, the most stringent, would also be an across the board RTC reduction affecting all RECLAIM facilities and investors, but would not include the 10 percent compliance margin or the BARCT adjustment for refinery equipment. The total RTC reduction would be 15.82 tons per day under this approach and the RTC holdings would be shaved by 60 percent overall.

CEQA Alternative 3: This approach has been proposed by industry representatives and is an across the board shave that would affect all RECLAIM facilities and investors. For this calculation, the base year emissions at the proposed BARCT level would be subtracted from the base year emissions at the previous BARCT level (Year 2000 or 2005). The result would be an RTC reduction of 33 percent to all RECLAIM facilities and investors.

CEQA Alternative 4: This is the "No Project" approach and no RTC reduction would be applied to any RECLAIM facility or investor.

CEQA Alternative 5: This approach would affect all RECLAIM facilities and investors. The RTC reductions would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 66 percent. For non-major refineries and all other facilities, the RTC holdings would be shaved by 37 percent.

Table U.3 - NOx RECLAIM Shave Options and CEQA Alternatives

		Major Refineries/ Investors	Non-Major Facilities	~~Electrical~~ Electrcity Generating Facilities	Bottom 10% of Holders
	Staff Proposal Under Consideration				
Staff Proposal	**Shave applied to 90% of RTC Holders (Weighted by BARCT Reduction Contribution)** *56 total facilities, plus investors as 1 company, and includes 47 non-major refinery facilities*	**66~~7~~%** **(9 Facilities)**	**49~~6~~%** **(26 Facilities)**	**49~~6~~%** **(21 Facilities)**	**0%** **(219 Facilities)**
	CEQA Alternatives Under Consideration				
CEQA Alternative #1	**Across the Board** *Affects all facilities and investors*	**53%**	**53%**	**53%**	**53%**
CEQA Alternative #2	**Most Stringent Approach** *Across the Board without 10% Compliance Margin*	**60%**	**60%**	**60%**	**60%**
CEQA Alternative #3	**Industry Approach** *Across the Board: Difference between previous BARCT and new BARCT*	**33%**	**33%**	**33%**	**33%**
CEQA Alternative #4	**No Project**	**0%**	**0%**	**0%**	**0%**
CEQA Alternative #5	**Weighted by BARCT Reduction Contribution** *Affects all facilities and investors*	**66%**	**37%**	**37%**	**37%**

Tradable/Usable and Non-Tradable/Non-Usable Factors in Rule 2002(f)(1)(B) and (C)

The Tradable/Usable NOx Adjustment Factor is derived by dividing the amount of RTCs remaining after the shave for each compliance year by the total holdings prior to the beginning of the shave (September 22, 2015). For those facilities subject to subparagraph (f)(1)(B) [listed in Rule 2002 Table 7] the total Infinite Year Block (IYB) total holdings in 2022 prior to the beginning of the shave is 14.57 tons per day. Similarly, for those facilities subject to subparagraph (f)(1)(C) [listed in Rule 2002 Table 8] the total holdings prior to the beginning of the shave is 9.09 tons per day. Both of these values are presented in Table U.2 of this report.

The proposed RTC reduction for each compliance year is presented in Chapter 5 of this report are:

2016: 4 tons per day
2017: 0 tons per day
2018: 2 tons per day
2019: 2 tons per day
2020: 2 tons per day
2021: 2 tons per day
2022 2 tons per day

The proportion of RTC reductions based on initial holdings and remaining RTC for the Table 7 and Table 8 facilities are as follows:

Compliance Year	Table 7 Facilities		Table 8 Facilities	
	Reductions (TPD)	A_i Remaining (TPD)	Reductions (TPD)	B_i Remaining (TPD)
2016:	2.74	11.83	1.26	7.82
2017:	0	11.83	0	7.82
2018:	1.37	10.46	0.63	7.20
2019:	1.36	9.11	0.64	6.56
2020:	1.37	7.74	0.63	5.93
2021:	1.37	6.37	0.64	5.30
2022	1.38	4.99	0.63	4.67

The Tradable/Usable NOx Adjustment Factor is calculated as follows:

Table 7 Facilities = $A_i/14.57$

Table 8 Facilities = $B_i/9.09$

The Non-tradable/Non-usable NOx Adjustment Factor is derived by dividing the annual amount of RTC reductions starting in 2016 by the total holdings prior to the beginning of the shave. For the Table 7 and 8 facilities the annual amount of Non-tradable/Non-Usable holdings would be as follows:

Compliance Year	Table 7 Facilities RTC Reductions		Table 8 Facilities RTC Reductions	
	Annual (C_i) (TPD)	**Adjustment Factor**	**Annual (D_i) (TPD)**	**Adjustment Factor**
2015	0	0	0	0
2016	2.74	0.188	1.26	0.139
2017	0	0	0	0
2018:	1.37	0.094	0.63	0.069
2019:	1.37	0.093	0.63	0.07
2020:	1.37	0.094	0.63	0.069
2021:	1.37	0.094	0.63	0.07
2022	1.37	0.094	0.63	0.069
2023 and after	0	0	0	0

The Non-tradable/Non-usable NOx Adjustment Factor is calculated as follows:

Table 7 Facilities = $C_i/14.57$

Table 8 Facilities = $D_i/9.09$

Regional NSR Holding Account

In addition to the Non-tradable/Non-usable account, newer ~~electrical~~ electricity generating facilities subject to the shave with ongoing NSR holding requirements (entered RECLAIM after October 15, 1993) will have access to this account under specific circumstances, which will be funded by the shaved portion of each affected facility's holdings for every compliance year of the shave beginning in 2017. At the end of the shave, 49% of the holdings from newer ~~electrical~~ electricity generating facilities subject to NSR requirements will be held in the Regional account. For the first year of the shave, however, there will be no portion that will go into the account. The funding will begin on the second year, when the non-tradable account holdings expire. Access to credits for the purposes of NSR or compliance with annual emissions in the first year of the shave will be provided by the non-tradable account if the rolling average RTC threshold price trigger is reached or in a State of Emergency for power generation declared by the Governor in the Basin. The table below contains the yearly and cumulative holdings that will go into the account:

Compliance Year	Holdings for Regional NSR Holding Account (tpd)	Cumulative Balance (tpd)
2016	0	0
2017	0.237	0.237
2018	0	0.237
2019	0.118	0.355
2020	0.118	0.473
2021	0.118	0.591
2022	0.118	0.709
2023+	0.118	0.827

The total holdings that will be contained in the Regional NSR Holding Account programmatically will be 0.83 tons per day in 2023 and beyond.

The list of ~~electrical~~ electricity generating facilities in the top 90% of RTC holders that are subject to NSR holding requirements and are eligible to use the Regional Account for NSR purposes are as follows:

Facility ID	Facility Name
160437	SOUTHERN CALIFORNIA EDISON
152707	CPV SENTINEL LLC
146536	WALNUT CREEK ENERGY, LLC
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA
115314	LONG BEACH GENERATION, LLC
153992	CANYON POWER PLANT
155474	BICENT (CALIFORNIA) MALBURG LLC
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC
129816/ 700126	INLAND EMPIRE ENERGY CENTER, LLC/ GENERAL ELECTRIC COMPANY

Table 9 in Rule 2002 lists these facilities and the specific yearly RTC balances that will go to the Regional NSR Holding account from compliance year 2016 and beyond. In 2023, the account would reach full funding and will carry over every year for the purposes of fully or partially fulfilling each facility's NSR demonstration.

Appendix V – 2011 Audited Emissions of 20 tons per day

The 2011 audited NOx emissions for the 281 facilities in RECLAIM are shown in Table V-1.

Table V. 1 - 2011 Audited Emissions

			2011 Emissions (lbs)	2011 Emissions (tpd)
1	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1,231,852	1.69
2	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	407,394	0.56
3	151798	TESORO REFINING AND MARKETING CO, LLC	93,488	0.13
4	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1,143,902	1.57
5	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	673,652	0.92
6	800026	ULTRAMAR INC (NSR USE ONLY)	534,363	0.73
7	800030	CHEVRON PRODUCTS CO.	1,425,393	1.95
8	800089	EXXONMOBIL OIL CORPORATION	1,602,233	2.19
9	800183	PARAMOUNT PETR CORP (EIS USE)	104,249	0.14
10	800436	TESORO REFINING AND MARKETING CO, LLC	1,171,965	1.61
		Total Refineries		**11.49**
1	4242	SAN DIEGO GAS & ELECTRIC	142,751	0.20
2	4477	SO CAL EDISON CO	137,290	0.19
3	5973	SO CAL GAS CO	88,258	0.12
4	7427	OWENS-BROCKWAY GLASS CONTAINER INC	135,486	0.19
5	11435	PQ CORPORATION	81,270	0.11
6	15504	SCHLOSSER FORGE COMPANY	52,331	0.07
7	18931	TAMCO	226,012	0.31
8	22911	CARLTON FORGE WORKS	48,839	0.07
9	46268	CALIFORNIA STEEL INDUSTRIES INC	464,990	0.64
10	51620	WHEELABRATOR NORWALK ENERGY CO INC	89,025	0.12
11	114801	RHODIA INC.	48,878	0.07
12	115389	AES HUNTINGTON BEACH, LLC	98,993	0.14
13	115394	AES ALAMITOS, LLC	80,929	0.11
14	119907	BERRY PETROLEUM COMPANY	131,857	0.18
15	124838	EXIDE TECHNOLOGIES	62,824	0.09
16	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49,983	0.07
17	129497	THUMS LONG BEACH CO	66,364	0.09
18	129816	INLAND EMPIRE ENERGY CENTER, LLC	105,857	0.15
19	160437	SOUTHERN CALIFORNIA EDISON	204,132	0.28
20	166073	BETA OFFSHORE	391,977	0.54
21	171960	TIN, INC. DBA INTERNATIONAL PAPER	327,637	0.45
22	800074	LA CITY, DWP HAYNES GENERATING STATION	205,022	0.28
23	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	103,988	0.14
24	800128	SO CAL GAS CO (EIS USE)	461,243	0.63
25	800193	LA CITY, DWP VALLEY GENERATING STATION	166,413	0.23
26	800330	THUMS LONG BEACH	49,657	0.07
27	800335	LA CITY, DEPT OF AIRPORTS	73,245	0.10
		Total non-refineries		**5.61**
		Total for top 37 emitting facilities		**17.10**

1	800189	DISNEYLAND RESORT	47,216	0.06
2	8547	QUEMETCO INC	46,831	0.06
3	126498	STEELSCAPE, INC	46,420	0.06
4	101656	AIR PRODUCTS AND CHEMICALS, INC.	44,275	0.06
5	8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	42,884	0.06
6	800168	PASADENA CITY, DWP (EIS USE)	41,370	0.06
7	115536	AES REDONDO BEACH, LLC	40,890	0.06
8	9755	UNITED AIRLINES INC	40,626	0.06
9	94872	METAL CONTAINER CORP	39,730	0.05
10	800080	LUNDAY-THAGARD COMPANY	39,275	0.05
11	155474	BICENT (CALIFORNIA) MALBURG LLC	38,772	0.05
12	105903	PRIME WHEEL	37,852	0.05
13	43436	TST, INC.	35,778	0.05
14	148236	AIR LIQUIDE LARGE INDUSTRIES U.S., LP	33,031	0.05
15	3417	AIR PROD & CHEM INC	32,660	0.04
16	14495	VISTA METALS CORPORATION	30,433	0.04
17	139010	RIPON COGENERATION LLC	30,419	0.04
18	16639	SHULTZ STEEL CO	30,415	0.04
19	47781	OLS ENERGY-CHINO	29,938	0.04
20	550	LA CO., INTERNAL SERVICE DEPT	29,202	0.04
21	118406	CARSON COGENERATION COMPANY	28,760	0.04
22	155877	MILLERCOORS, LLC	28,439	0.04
23	800409	NORTHROP GRUMMAN SYSTEMS CORPORATION	27,489	0.04
24	800037	DEMENNO/KERDOON	26,951	0.04
25	16338	KAISER ALUMINUM FABRICATED PRODUCTS, LLC	25,667	0.04
1	136	PRESS FORGE CO	25,407	0.03
2	3704	ALL AMERICAN ASPHALT, UNIT NO.01	24,416	0.03
3	16642	ANHEUSER-BUSCH LLC., (LA BREWERY)	23,205	0.03
4	35302	OWENS CORNING ROOFING AND ASPHALT, LLC	23,022	0.03
5	800170	LA CITY, DWP HARBOR GENERATING STATION	22,609	0.03
6	115663	EL SEGUNDO POWER, LLC	21,639	0.03
7	11887	NASA JET PROPULSION LAB	21,140	0.03
8	153992	CANYON POWER PLANT	21,077	0.03
9	17953	PACIFIC CLAY PRODUCTS INC	20,635	0.03
10	346	FRITO-LAY, INC.	20,492	0.03
11	68042	CORONA ENERGY PARTNERS, LTD	19,286	0.03
12	18294	NORTHROP GRUMMAN CORP, AIRCRAFT DIV	18,299	0.03
13	3585	R. R. DONNELLEY & SONS CO, LA MFG DIV	16,710	0.02
14	800016	BAKER COMMODITIES INC	16,616	0.02
15	12428	NEW NGC, INC.	16,418	0.02
16	7411	DAVIS WIRE CORP	16,090	0.02
17	83102	LIGHT METALS INC	15,731	0.02
18	54402	SIERRA ALUMINUM COMPANY	15,677	0.02
19	117785	BALL METAL BEVERAGE CONTAINER CORP.	15,323	0.02
20	117290	B BRAUN MEDICAL, INC	15,167	0.02
21	151532	LINN OPERATING, INC	15,146	0.02
22	800408	NORTHROP GRUMMAN SYSTEMS	14,835	0.02
23	52517	REXAM BEVERAGE CAN COMPANY	14,827	0.02

24	115172	RAYTHEON COMPANY	14,365	0.02
25	21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	14,070	0.02
26	800088	3M COMPANY	13,446	0.02
27	800113	ROHR, INC.	12,593	0.02
28	115563	NCI GROUP INC., DBA, METAL COATERS OF CA	12,471	0.02
29	115314	LONG BEACH PEAKERS LLC	12,363	0.02
30	1073	BORAL ROOFING LLC	12,063	0.02
31	23752	AEROCRAFT HEAT TREATING CO INC	11,919	0.02
32	45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	11,885	0.02
33	3029	MATCHMASTER DYEING & FINISHING INC	11,691	0.02
34	127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	11,529	0.02
35	43201	SNOW SUMMIT INC	11,028	0.02
36	800066	HITCO CARBON COMPOSITES INC	10,783	0.01
37	115315	GEN ON WEST, LP	10,625	0.01
38	61962	LA CITY, HARBOR DEPT	10,436	0.01
39	9053	VEOLIA ENERGY LOS ANGELES, INC	10,120	0.01
40	53729	TREND OFFSET PRINTING SERVICES, INC	10,005	0.01
41	97081	THE TERMO COMPANY	9,943	0.01
42	85943	SIERRA ALUMINUM COMPANY	9,856	0.01
43	22364	ITT CORPORATION	9,853	0.01
44	45471	O N I S, DBA, CARMEUSE INDUSTRIAL SANDS	9,784	0.01
45	800393	VALERO WILMINGTON ASPHALT PLANT	9,556	0.01
46	16978	CLOUGHERTY PACKING LLC/HORMEL FOODS CORP	9,424	0.01
47	61722	RICOH ELECTRONICS INC	9,200	0.01
48	22607	CALIFORNIA DAIRIES, INC	9,148	0.01
49	115241	BOEING SATELLITE SYSTEMS INC	9,142	0.01
50	101977	SIGNAL HILL PETROLEUM INC	8,791	0.01
51	131732	NEWPORT FAB, LLC	8,769	0.01
52	21598	ANGELICA TEXTILE SERVICES	8,675	0.01
53	139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	8,579	0.01
54	123774	HERAEUS PRECIOUS METALS NO. AMERICA, LLC	8,552	0.01
55	16737	ATKINSON BRICK CO	8,448	0.01
56	145836	AMERICAN APPAREL DYEING & FINISHING, INC	8,416	0.01
57	130211	PAPER-PAK INDUSTRIES	8,385	0.01
58	132068	BIMBO BAKERIES USA INC	8,379	0.01
59	800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	8,284	0.01
60	157359	HENKEL ELECTRONIC MATERIALS, LLC	7,990	0.01
61	800196	AMERICAN AIRLINES INC (EIS USE)	7,985	0.01
62	115130	VERTIS, INC	7,890	0.01
63	37603	SGL TECHNIC INC, POLYCARBON DIVISION	7,638	0.01
64	19390	SULLY-MILLER CONTRACTING CO.	7,459	0.01
65	38872	MARS PETCARE U.S., INC.	7,248	0.01
66	131850	SHAW DIVERSIFIED SERVICES INC	7,207	0.01
67	3721	DART CONTAINER CORP OF CALIFORNIA	7,078	0.01
68	107656	CALMAT CO	7,014	0.01

69	56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	7,004	0.01
70	2825	MCP FOODS INC	6,991	0.01
71	800150	US GOVT, AF DEPT, MARCH AIR RESERVE BASE	6,892	0.01
72	11119	THE GAS CO./ SEMPRA ENERGY	6,820	0.01
73	152501	PRECISION SPECIALTY METALS, INC.	6,773	0.01
74	2912	HOLLIDAY ROCK CO INC	6,761	0.01
75	59618	PACIFIC CONTINENTAL TEXTILES, INC.	6,659	0.01
76	19167	R J NOBLE COMPANY	6,626	0.01
77	40034	BENTLEY PRINCE STREET INC	6,205	0.01
78	25638	BURBANK CITY, BURBANK WATER & POWER	6,137	0.01
79	800038	THE BOEING COMPANY - C17 PROGRAM	6,092	0.01
80	18455	ROYALTY CARPET MILLS INC	5,997	0.01
81	138568	CALIFORNIA DROP FORGE, INC	5,977	0.01
82	114997	RAYTHEON COMPANY	5,819	0.01
83	153199	THE KROGER CO/RALPHS GROCERY CO	5,639	0.01
84	161300	SAPA EXTRUDER, INC	5,600	0.01
85	96587	TEXOLLINI INC	5,573	0.01
86	165192	TRIUMPH AEROSTRUCTURES, LLC	5,464	0.01
87	115277	LAFAYETTE TEXTILE IND LLC	5,409	0.01
88	74424	ANGELICA TEXTILE SERVICES	5,347	0.01
89	137471	GRIFOLS BIOLOGICALS INC	5,246	0.01
90	153033	GEORGIA-PACIFIC CORRUGATED LLC	5,223	0.01
91	12155	ARMSTRONG WORLD INDUSTRIES INC	5,032	0.01
92	73022	US AIRWAYS INC	4,988	0.01
93	107654	CALMAT CO	4,897	0.01
94	156722	AMERICAN APPAREL KNIT AND DYE	4,841	0.01
95	11034	VEOLIA ENERGY LOS ANGELES, INC	4,831	0.01
96	800003	HONEYWELL INTERNATIONAL INC	4,826	0.01
97	141295	LEKOS DYE AND FINISHING, INC	4,686	0.01
98	124619	ARDAGH METAL PACKAGING USA INC.	4,543	0.01
99	155221	SAVE THE QUEEN LLC (DBA QUEEN MARY)	4,224	0.01
100	1744	KIRKHILL - TA COMPANY	4,003	0.01
101	11716	FONTANA PAPER MILLS INC	3,971	0.01
102	800417	PLAINS WEST COAST TERMINALS LLC	3,963	0.01
103	133987	PLAINS EXPLORATION & PRODUCTION CO, LP	3,883	0.01
104	143741	DCOR LLC	3,850	0.01
105	800149	US BORAX INC	3,825	0.01
106	63180	DARLING INTERNATIONAL INC	3,659	0.01
107	148925	CHERRY AEROSPACE	3,634	0.00
108	20604	RALPHS GROCERY CO	3,629	0.00
109	800094	EXXONMOBIL OIL CORPORATION	3,545	0.00
110	20203	RECYCLE TO CONSERVE INC.	3,542	0.00

110	20203	RECYCLE TO CONSERVE INC.	3,542	0.00
111	800067	BOEING SATELLITE SYSTEMS INC	3,409	0.00
112	117140	AOC, LLC	3,247	0.00
113	167066	ARLON GRAPHICS L.L.C.	3,239	0.00
114	5998	ALL AMERICAN ASPHALT	3,235	0.00
115	114264	ALL AMERICAN ASPHALT	3,233	0.00
116	15544	REICHHOLD INC	3,189	0.00
117	800338	SPECIALTY PAPER MILLS INC	3,097	0.00
118	800431	PRATT & WHITNEY ROCKETDYNE, INC.	3,028	0.00
119	17956	WESTERN METAL DECORATING CO	3,023	0.00
120	2946	PACIFIC FORGE INC	2,938	0.00
121	113160	HILTON COSTA MESA	2,936	0.00
122	42630	PRAXAIR INC	2,737	0.00
123	157363	INTERNATIONAL PAPER CO	2,661	0.00
124	107653	CALMAT CO	2,577	0.00
125	17623	LOS ANGELES ATHLETIC CLUB	2,511	0.00
126	50098	D&D DISPOSAL INC,WEST COAST RENDERING CO	2,501	0.00
127	98159	PACIFIC COAST ENERGY COMPANY LP	2,384	0.00
128	125015	LOS ANGELES TIMES COMMUNICATIONS LLC	2,339	0.00
129	95212	FABRICA	2,296	0.00
130	14871	SONOCO PRODUCTS CO	2,291	0.00
131	3968	TABC, INC	2,283	0.00
132	156741	HARBOR COGENERATION CO, LLC	2,277	0.00
133	124808	INEOS POLYPROPYLENE LLC	2,247	0.00
134	112853	NP COGEN INC	2,206	0.00
135	107655	CALMAT CO	2,182	0.00
136	2418	FRUIT GROWERS SUPPLY CO	2,083	0.00
137	94930	CARGILL INC	2,032	0.00
138	133813	EI COLTON, LLC	1,965	0.00
139	14049	MARUCHAN INC	1,949	0.00
140	168088	PCCR USA	1,903	0.00
141	800325	TIDELANDS OIL PRODUCTION CO	1,872	0.00
142	25058	EXXONMOBIL OIL CORP	1,787	0.00
143	800127	SO CAL GAS CO (EIS USE)	1,778	0.00
144	143740	DCOR LLC	1,741	0.00
145	105277	SULLY MILLER CONTRACTING CO	1,740	0.00
146	800181	CALIFORNIA PORTLAND CEMENT CO (NSR USE)	1,727	0.00
147	10094	ATLAS CARPET MILLS INC	1,726	0.00
148	117227	SHCI SM BCH HOTEL LLC, LOEWS SM BCH HOTE	1,724	0.00
149	158950	WINDSOR QUALITY FOOD CO. LTD.	1,701	0.00
150	800420	PLAINS WEST COAST TERMINALS LLC	1,690	0.00
151	42775	WEST NEWPORT OIL CO	1,661	0.00
152	143738	DCOR LLC	1,570	0.00
153	144455	LIFOAM INDUSTRIES, LLC	1,497	0.00
154	164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	1,476	0.00

155	14736	THE BOEING COMPANY	1,458	0.00
156	169754	OXY USA INC	1,438	0.00
157	800416	PLAINS WEST COAST TERMINALS LLC	1,426	0.00
158	800110	THE BOEING COMPANY	1,369	0.00
159	800371	RAYTHEON SYSTEMS COMPANY - FULLERTON OPS	1,302	0.00
160	111415	VAN CAN COMPANY	1,268	0.00
161	115041	RAYTHEON COMPANY	1,188	0.00
162	800210	CONEXANT SYSTEMS INC	1,166	0.00
163	132071	DEAN FOODS CO. OF CALIFORNIA	1,164	0.00
164	151594	OXY USA, INC	1,132	0.00
165	5814	GAINEY CERAMICS INC	1,126	0.00
166	7416	PRAXAIR INC	1,108	0.00
167	124723	GREKA OIL & GAS, INC	1,025	0.00
168	17344	EXXONMOBIL OIL CORP	977	0.00
169	148340	THE BOEING CO. COMMERCIAL AVIATION SRVCS	950	0.00
170	14926	SEMPRA ENERGY (THE GAS CO)	948	0.00
171	89248	OLD COUNTRY MILLWORK INC	930	0.00
172	129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	866	0.00
173	800205	BANK OF AMERICA NT & SA, BREA CENTER	859	0.00
174	132191	PURENERGY OPERATING SERVICES, LLC	826	0.00
175	68118	TIDELANDS OIL PRODUCTION COMPANY ETAL	823	0.00
176	12372	MISSION CLAY PRODUCTS	787	0.00
177	16660	THE BOEING COMPANY	761	0.00
178	142267	FS PRECISION TECH LLC	739	0.00
179	47771	DELEO CLAY TILE CO INC	657	0.00
180	151899	VINTAGE PRODUCTION CALIFORNIA LLC	645	0.00
181	133996	PLAINS EXPLORATION & PRODUCTION COMPANY	611	0.00
182	14944	CENTRAL WIRE, INC.	564	0.00
183	800264	EDGINGTON OIL COMPANY	481	0.00
184	800182	RIVERSIDE CEMENT CO (EIS USE)	456	0.00
185	800344	CALIFORNIA AIR NATIONAL GUARD, MARCH AFB	425	0.00
186	40483	NELCO PROD. INC	282	0.00
187	160888	HINES REIT EL SEGUNDO, LP	271	0.00
188	125579	DIRECTV	268	0.00
189	9217	VEOLIA ENERGY LOS ANGELES, INC	220	0.00
190	14502	VERNON CITY, LIGHT & POWER DEPT	172	0.00
191	137508	TONOGA INC, TACONIC DBA	93	0.00
192	143739	DCOR LLC	79	0.00
193	2083	SUPERIOR INDUSTRIES INTERNATIONAL INC	75	0.00
194	142536	DRS SENSORS & TARGETING SYSTEMS, INC	72	0.00
195	149491	BOEING REALTY CORP	49	0.00
196	132192	PURENERGY OPERATING SERVICES, LLC	29	0.00
197	800373	CENCO REFINING COMPANY	25	0.00
198	12185	US GYPSUM CO	5	0.00

199	141555	CASTAIC CLAY PRODUCTS, LLC	4	0.00
200	151394	LINN WESTERN OPERATING INC	4	0.00
201	152054	LINN WESTERN OPERATING INC	3	0.00
202	58622	LOS ANGELES COLD STORAGE CO	1	0.00
203	151415	LINN WESTERN OPERATING, INC	1	0.00
204	1634	STEELCASE INC, WESTERN DIV	0	0.00
205	15164	HIGGINS BRICK CO	0	0.00
206	20543	REDCO II	0	0.00
207	23196	SUNKIST GROWERS, INC	0	0.00
208	38440	COOPER & BRAIN - BREA	0	0.00
209	42676	CES PLACERITA INC	0	0.00
210	119104	CALMAT CO	0	0.00
211	137520	PLAINS WEST COAST TERMINALS LLC	0	0.00
212	146536	WALNUT CREEK ENERGY, LLC	0	0.00
213	148896	VINTAGE PRODUCTION CALIFORNIA LLC	0	0.00
214	148897	VINTAGE PRODUCTION CALIFORNIA LLC	0	0.00
215	151601	OXY USA, INC.	0	0.00
216	152707	CPV SENTINEL LLC	0	0.00
217	152857	GEORGIA-PACIFIC GYPSUM LLC	0	0.00
218	800343	BOEING SATELLITE SYSTEMS, INC	0	0.00
219	800419	PLAINS WEST COAST TERMINALS LLC	0	0.00
	TOTAL (281 Facilities by end of June 2011)			**20.006**
	Note: August 29, 2013 data from RECLAIM Admin team			

Appendix W – 2012 Emissions for ~~Power~~ Electricity Generating Sector

The base year for the BARCT analysis is compliance year 2011. However, the 2011 base year would not be appropriate for this source category due to the uniqueness of its operations. There have been several changes within recent years that have warranted the use of more recent base year data.

The San Onofre Nuclear Generating Station (SONGS) has not been in operation since early 2012 and is now undergoing decommissioning. The power deficit was to be made up by other natural gas fired units in the region. Other existing units are subject to the once-through-cooling (OTC) regulation and will have to be repowered. These repowered units are predicted to be more efficient units that consume less natural gas to produce the same amount of power as their predecessors. Other trends in the industry have begun to affect power availability such as the increased use of renewable power, like wind, water, and solar. The state of California must meet a 33% Renewable Portfolio Standard by 2020, and the inherent volatility of these renewable energy sources means that gas demand must be met almost in real time.

The growth factor for ~~electrical~~ electricity generating facilities came from the 2012 California Gas Report, consistent with what is used for the AQMP projections for these facilities. However, ~~B~~based on the 2014 California Gas Report, gas demand in the future is set to decrease slightly due to the utilization of more efficient ~~electrical~~ electricity generating facilities, greenhouse gas (GHG) reductions, and the increased use of renewable power. The projected emissions in 2023 using compliance year 2011 as the base year used growth factors from SCAG (Southern California Association of Governments) for non-~~electrical~~ electricity generating facilities.

Table W. 1 - Compliance Year 2011 ~~Power~~ Electricity Generating Sector Emissions

Compliance Year 2011 Emissions (tpd)	2011 Emissions at BARCT/BACT (tpd)	Growth Factor	2023 Emissions with Growth (tpd)
1.45	2.57	1.146	2.95

The figures above included those ~~electrical~~ electricity generating facilities among the top 37 NOx emitters in compliance year 2011. An additional 0.34 tons per day came from ~~electrical~~ electricity generating facilities outside the top 37 and was included as part of the “Other Sources” category with a different growth factor.

More recent base year data was obtained using calendar year AER (Annual Emissions Report) fuel usage data for 2012. The calendar year 2012 emissions include those for the major sources only belonging to electric generating facility source category (includes boilers, gas turbines, and ICEs). The emissions from process units and any Rule 219 equipment are almost negligible (the emissions from process units in 2011 were 0.006 tpd).

Table W. 2 - 2012 ~~Power~~ Electricity Generating Sector Emissions Based on Annual Emission Reports (AER) Fuel Usage

Calendar Year 2012 Emissions (tpd)	2012 Emissions at BARCT/BACT (tpd)	Growth Factor	2023 Emissions with Growth (tpd)
2.50	2.35	0.8683	2.04

The growth factor was extrapolated from the tables in the ~~2104~~ 2014 California Gas Report and it shows a slight decrease in demand for natural gas. There were nine ~~electrical~~ electricity generating facilities among the top 37 emitters in compliance year 2011. For this updated analysis, all ~~electrical~~ electricity generating facilities in RECLAIM were included (30 in total) and their emissions at the BARCT or BACT level were calculated. Most of the units are already meeting BARCT or BACT requirements, due to previous rule requirements.

Another unique aspect of the ~~power~~ electricityl generating sector is that many of the newer units are subject to new source review (NSR) holding requirements. Per Rule 2005, if a facility is new (received all its District permits on or after October 15, 1993), it must hold sufficient RTCs in advance of every year at the equipment's potential to emit level. Virtually all power generating units typically operate at a level far below its potential to emit, but the facility must still hold the RTCs to comply with the NSR demonstration. Stakeholders have brought to SCAQMD staff's attention their concern about the shave and whether a power generating facility can still comply with its emission allocation and NSR demonstration concurrently, especially when there is no cost effective method to retrofit their equipment to generate credits.

SCAQMD staff has proposed a safety valve for addressing the concerns of the ~~power~~ electricity generating sector. A Regional NSR Holding Account has been proposed that would consist of RTCs solely to meet the programmatic NSR holding demonstration. Under this approach, individual facility holding requirements would no longer be necessary. Concerns have also been raised in the event that a power emergency is experienced and there is an added demand for power production. SCAQMD staff has also proposed to allow access to the Regional NSR Holding Account if the Governor declares a state of emergency.

Appendix X – Proposed Changes in Rules 2001, 2002, 2005, 2011 and 2012

Rule 2001

Staff is proposing that the owner or operator of an electricity generating facility (EGF) would have the option of having their facility or facilities exit from the NOx RECLAIM program. This opting out of NOx RECLAIM is contingent on the submittal of a plan application subject to plan fees specified in Rule 306. To request this opting-out of the NOx RECLAIM program the following requirements are must be met as demonstrated in an opt-out plan submitted to the Executive Officer:

- At least 99 percent of the EGF's NOx emissions for the most recent three full compliance years are from equipment that meets current Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT), for NOx.
- The EGF is subject to NOx RECLAIM as of the date of the amendment or has been subject to NOx RECLAIM for at least 10 years as of the plan submittal date.

For the purposes of Rule 2001, an EGF is defined as a NOx RECLAIM facility that generates electricity for distribution in the state or local grid system. However, this type of facility would not include a cogeneration facility. That is, a facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

Based on the timing that the EGF entered RECLAIM and as part of the opting-out procedures the EGF Facility Permit holder must submit applications to include in its permit and accept permit conditions that ensure all of the following apply:

- For an EGF~~s for which all permits were issued on or after January 1, 1994~~ that does not meet the definition of an existing facility, as defined in Rule 2000(c)(35), the quantity of NOx RTCs for all compliance years after the date of approval of the opt-out plan and required to be held by the facility pursuant to Rule 2005 – New Source Review for RECLAIM must be surrendered by the EGF, retired from the market, and used to satisfy any NOx requirements for continuing obligations under Regulation XIII – New Source Review. If needed to equal this amount, any Non-tradable/Non-usable RTCs and any RTCs corresponding to the EGF's contribution to the Regional NSR Holding Account may be used for this purpose and, if so used, would be removed from the Account.

- For existing EGFs, an amount of NOx RTCs equivalent to the facility's NOx holdings as of September 22, 2015 for all compliance years after the date of approval of the opt-out plan must be surrendered by the EGF, retired from the market.
- Any NOx RTCs held by an EGF beyond those referred above may be sold, traded, or transferred used by the EGF.

Other important requirements associated with EGFs opting-out of NOx RECLAIM include:

- That the EGF operator ensures that all equipment identified in the opt-out plan as meeting BACT or BARCT must not exceed at its respective BACT or BARCT levels of emissions or any existing permit condition limiting NOx emission that is lower than BACT or BARCT as of the date of the opt-out plan submittal.
- Limits on EGF Emissions ~~*For existing EGFs, total facility emissions shall be limited to the amount of Compliance Year 2015 RTCs held as of September 22, 2015. The facility NOx emission limit shall be apportioned to each NOx source in the same proportion as its share of the EGF's emissions during the three complete compliance years prior to the date of opt-out plan submittal.*~~

  - For existing EGFs the total facility emissions would be limited to the amount of Compliance Year 2015 RTCs held as of September 22, 2015.
  - For an EGF that does not meet the definition of an existing facility emissions from each NOx source would be limited to the amount of RTCs required to be held for that source pursuant to Rule 2005 as of the date of opt-out plan submittal.

The owner or operator of multiple EGFs under common control would have one opportunity to apportion the NOx emission limits among its facilities under common control, provided all of the facilities opt out concurrently. The apportionment must be described in the opt-out plan that shall be submitted to the Executive Officer. Each facility shall not have a limit that exceeds the amount of emissions that can be generated by all existing equipment located at the facility. For EGFs for which all permits were issued on or after January 1, 1994, emissions from each NOx source must be limited to the amount of RTCs required to be held for that source pursuant to Rule 2005 as of the date of the opt-out plan submittal.

- Subdivision (j) shall not be applicable to the EGF for any equipment installed or modified after the date of approval of the opt-out plan, and for existing equipment at the earliest practicable date but no later than three years after the date of the approved opt-out plan.
- The EGF operator must continue to comply with the requirements of Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions and its associated protocols unless the Executive Officer has approved an alternative monitoring and recordkeeping plan which is sufficient to determine compliance with all applicable rules.
- ~~o.~~ For EGFs not subject to Regulation XXX – Title V Permits, the EGF's permit must be re-designated as an "opt-out facility permit" and shall remain in effect, subject to annual renewal, unless expired, revoked, or modified pursuant to applicable rules. The EGF operator must continue to pay RECLAIM permit fees pursuant to Rule 301(l).
- After an EGF is removed out of NOx RECLAIM, Regulations XI and XIII would apply.

The Executive Officer would approve or deny the opt-out plan within 180 days of receipt of a complete plan, unless the EGF and the Executive Officer have mutually agreed upon a longer time period~~.~~ The Executive Officer will not approve the opt-out plan unless it has been determined that the abovementioned requirements are met (also see subparagraphs (g)(1)(A) and (g)(1)(B)) and the EGF accepts appropriate permit conditions to ensure proper compliance as specified above (also see subparagraphs (g)(2)(B) through (~~G~~H)). If, within 180 days or within the mutually agreed upon time period of receiving a complete opt-out plan, the Executive Officer does not take action on it, the EGF may consider it denied and petition the Hearing Board. The Executive Officer shall not re-issue the facility permit removing the EGF from RECLAIM unless the EGF surrendered the required amount of RTCs pursuant to subparagraph (g)(2)(A). Removal from RECLAIM of an EGF with an approved opt-out plan is effective upon issuance of a facility permit incorporating the conditions mentioned above (also see paragraph (g)(2)).

As currently specified no facility, on the initial Facility Listing or subsequently admitted to RECLAIM, may opt out of the program, unless approved by the Executive Officer according to above described requirements associated with an EGF.

The EGF option of exiting from the NOx RECLAIM program is also mentioned as one of the several exemptions in 2001(i)(1) and (2).

Rule 2002

The purpose of Rule 2002 is to establish the methodology for calculating facility Allocations and adjustments to RTC holdings for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).

Rule 2002 provides an overview of the RECLAIM Allocations; the establishment of starting, year 2000 and 2003 Allocations, the annual Allocations for NOx and SOx and the adjustments to RTC holdings. Rule 2002 also specifies the requirement for establishing High Employment/Low Emissions (HILO) facilities, Non-Tradable Allocation Credits, and RTC Reduction Exemptions. In addition to these sections of the rule there are various tables specifying RECLAIM equipment emission factors and the identification of certain facilities status with regards to the RECLAIM Allocation adjustment.

The most substantive proposed rule amendments are found in subdivision (f) *Annual Allocations for NOx and SOx and Adjustments to RTC Holdings* as well as the additions of Table 7 - *List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(B)*, Table 8 - *List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(C)*, and Table 9 - *List of NOx RECLAIM Facilities for the Regional NSR Holding Account with Balances (in lbs).* ~~Staff is~~Other important proposed changes include updated and new RTC price threshold values removal of the ~~also proposing to remove subdivision (i)~~ *RTC Reduction Exemption*, and added a new requirement for facility and equipment shutdowns ~~from the Rule 2002~~.

The staff proposal calls for a programmatic reduction of 14 tons per day. Four tons per day would be reduced in 2016 and the remainder would be reduced in equal increments of 2 tons per day from 2018 to 2022. There would be no reductions proposed for the year 2017. These reductions are reflected in subparagraphs (f)(1)(B) and (f)(1)(C). Subparagraph (f)(1)(B) includes all of Major Refineries and Investors. The Major Refineries are listed in Table 7 of Rule 2002. Subparagraph (f)(1)(C) includes all other facilities subject to reductions in NOx RTCs. These facilities are listed in Table 8 of Rule 2002. These adjustment factors would also apply to subsequent owners of any of these facilities.

Thus the remaining NOx RTCs after a shave for any compliance year would be the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(B) multiplied by the RTC holdings (as of September 22, 2015) of all the Major Refineries and Investors listed in Table 7 plus the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(C) multiplied by the RTC holdings (as of September 22, 2015) of all the facilities listed in Table 8. For purposes of assigning the appropriate adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and the date of amendment will be based on a last in/first out basis. ~~at the time each transaction was registered.~~

Since the RTC reductions specified in subparagraph (f)(1)(A) have been realized the conversion of non-tradable/non-usable NOx RTCs to tradable/usable NOx RTCs is no longer applicable to the RTC reductions specified in this subparagraph. The tradable/usable NOx RTCs specified in subparagraph (f)(1)(A) would remain intact and used for calculating RTC reductions for facilities entering the RECLAIM program. However, a similar approach in applying adjustment factors previously specified in subparagraph (f)(1)(A) would now be applied to the RTC reductions specified in subparagraphs (f)(1)(B) and (f)(1)(C).

Many of the proposed amendments to Rule 2002 focus on what will be done to provide access to RTCs to affected ~~electrical~~ electricity generating facilities (EGF) in the RECLAIM program under a State of Emergency related to electricity demand or power grid stability ~~in the Basin~~within the SCAQMD jurisdictional boundaries. Other amendments focus on providing relief from burdensome New Source Review (NSR) holding requirement for newer ~~electrical~~ electricity generating facilities that entered RECLAIM after 1993.

New ~~electrical generating facilities~~ EGFs must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. Staff has identified ten (10) new ~~electrical~~ electricity generating facilities subject to this requirement. These facilities are listed in Table 9 of Rule 2002. Staff is providing in Table 9 the quantity of NOx RTCs commensurate to the shave amount for these ten new ~~electrical~~ electricity generating facilities. These RTCs would be placed in a Regional NSR Holding Account as per subparagraph (f)(1)(~~G~~F) for the specific purpose of helping to comply with the requirements specified in Rule 2005.

~~According to subparagraph (f)(1)(F), at the conclusion of any of the compliance years 2016 through 2022 if the NOx RTC prices have not exceeded the proposed $22,500 per ton threshold as specified in subparagraph (f)(1)(I) and a State of Emergency related to electricity demand or power grid stability in the Basin as specified in paragraph (f)(4) has not been declared by the Governor, then the Non-tradable/Non-usable NOx RTCs for that compliance year, except for those RTCs specified in subparagraph (f)(1)(G), shall be submitted as part of the State Implementation Plan commitment.~~ According to subparagraph (f)(1)(~~G~~F) the Executive Officer will transfer to a Regional NSR Holding account the amount of NOx RTCs holdings listed in Table 9 of this Rule from the corresponding facilities identified in the same table.~~.~~

The threshold of $15,000 per ton has been updated to $22,500 per ton, consistent with the cost-effectiveness threshold for additional analysis in the 2012 AQMP. (*2012 AQMP, Chapter 4: Control Strategy and Implementation, page 4-43*)

A companion provision to the abovementioned subparagraphs is subparagraph (f)(1)(~~H~~G) which states that for the purposes of meeting the NSR holding requirement as specified in subdivision (f) of Rule 2005, the facilities identified in Table 9 may use a combination of their Tradable/Usable and Non-tradable/Non-usable RTCs specified in subparagraph (f)(1)(C) and the amount for each facility listed in Table 9 which represent the RTCs in the Regional NSR Holding account.

~~Other than the updated price trigger, other proposed changes to subparagraph (f)(1)(I) require the Executive Officer to include in his report to the Governing Board a commitment and schedule to conduct a more rigorous analysis of the RECLAIM program.~~

The deletion of subparagraphs (f)(1)(D), (f)(1)(E), and (f)(1)(F) [existing rule designation] and proposed changes to subparagraphs (f)(1)(~~K~~L) and (f)(1)(~~L~~M) reflect the change from using the adjustment factors in (f)(1)(A) [previous NOx RECLAIM amendment] to the adjustment factors applied in this proposed amendment, as well as updated methods for determining allocations for existing facilities that enter RECLAIM.

Staff is proposing to add RTC price thresholds based on a 3-month averaging period and a minimum RTC price threshold based on a 12-month averaging period. As previously mentioned the current RTC price threshold based on a 12-month averaging period is proposed to be changed from $15,000 to $22,500 per ton.

With regards to the proposed 3-month averaging period staff will calculate the 3-month rolling average RTC price for all trades for the current compliance year. This running assessment will commence on May 1, 2016 with the NOx RTC prices averaged from January 1, 2016 through March 31, 2016. As with the 12-month rolling average staff will update the 3-month and once per month. [subparagraph (f)(1)(E)]

~~Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(A), i~~In the event that the NOx RTC prices exceed ~~$15,000~~$22,500 per ton (*discrete* current compliance year credits) based on the 12-month rolling average, or exceed $35,000 per ton (*discrete* current compliance year credits) based on the 3-month rolling average calculated pursuant to subparagraph (f)(1)(~~B~~E), the Executive Officer will report the determination to the Governing Board. If the Governing Board finds that the 12-month rolling average RTC price exceeds ~~$15,000~~$22,500 per ton or the 3-month rolling average RTC price exceeds $35,000 per ton, then the ~~incremental~~ Non-tradable/Non-usable NOx ~~reductions~~ RTCs, as specified in subparagraphs (f)(1)(~~D~~B) and (f)(1)(C) valid for the period in which the RTC price is found to have exceeded the applicable threshold,*compliance year in which Cycle 1 facilities are currently operating* shall be -converted to Tradable/Usable NOx RTCs upon Governing Board concurrence. According to subparagraph (f)(1)(~~J~~F), in the event that the NOx RTC prices fall below $200,000 per ton (infinite year block) based on the 12-month rolling average staff will report the determination to the Governing Board. For the purpose of this rule, infinite year block refers to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

In the event that the infinite year block NOx RTC prices fall below $200,000 per ton based on the 12-month rolling average, calculated pursuant to subparagraph (f)(1)(E) beginning in 2019 for the compliance year in which Cycle 1 facilities are operating, the Executive Officer will report the determination to the Governing Board.
For the purpose of this rule, infinite year block refers to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

The addition of paragraph (f)(4) describes provisions to convert Non-tradable/Non-usable RTC~~S~~s and the Regional NSR Holding Account during a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries~~in the Basin~~. Specifically, such as a State of Emergency, the current compliance year Non-tradable/Non-usable NOx RTCs held by any electricity~~al~~ generating facilities that generate and distribute electricity to the grid system affected by the State of Emergency may be used to offset emissions after completely exhausting their own Tradable/Usable NOx RTCs.

If such a facility has completely exhausted their Non-tradable/Non-usable NOx RTCs, the owner or operator of the facility may apply for the use of the NOx RTCs in the Regional NSR Holding Account. The use of such RTCs in this Account would be based on availability at the end of each quarter. The owner or operator of each ~~electrical~~ electricity generating facility requesting NOx RTCs from the Regional NSR Holding Account would be required to submit a written request to the Executive Officer specifying the amount of RTCs needed and the basis for requesting the required amount.

The Executive Officer will determine the amount and distribution of the NOx RTCs from the Regional NSR Holding Account based on the requesting facility meeting the following criteria:

(i) The State of Emergency related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries~~in the Basin~~, as declared by the Governor, was the direct cause of the excess emissions.

(ii) The facility has been ordered to generate electricity in an increased amount and/or frequency due to the State of Emergency.

(iii) The facility has adequately demonstrated their need for the specific amount of RTCs from the Regional NSR Holding Account.

(iv) The facility owner or operator has not sold any part of their RTC holdings for the subject compliance year.

If the total RTCs requested exceed the supply of RTCs in this Account, the RTCs will be distributed proportionately according to the offset needs of the facilities on a quarterly basis. These RTCs will be non-tradable, but usable to offset emissions.

According to paragraph (f)(5) the Executive Officer will report to the Governing Board within 60 days of the end of the quarter in which the State of Emergency was declared~~declaration~~ by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries~~in the Basin~~. Included in this report will be, as applicable:

(i) the quantity of RTCs from the Regional NSR Holding Account that were distributed for compliance with the requirement to reconcile quarterly and annual emissions;

(ii) any adverse impacts that the State of Emergency is having on the RECLAIM program; and

(iii) any potential changes to the RECLAIM program that will be needed to help correct these impacts.

There has also been some changes to paragraph (f)(1)(L~~M~~) that pertain to NOx Allocations for existing facilities that enter RECLAIM after the date of adoption. For this rule provision for Compliance Year 2016 and all subsequent years the amount determined pursuant to subparagraph (d)(1)(A) except the variable B2 shall be the lowest of:

(i) The applicable 2000 (Tier I) Ending Emission Factor for the subject source(s) or process unit(s), as specified in Table 1 multiplied by the percentage inventory adjustment pursuant to subdivision (e) (0.72);
(ii) The BARCT Emission factor for the subject source as specified in Table 3; and
(iii) The proposed BARCT Emission factor for the subject as specified in Table 6.

For those facilities that are permanently shutting down, staff is proposing that their NOx RTCs will be retired from the NOx Program.

~~To that end starting on the date of amendment it is proposed that the highest ranking official of any facility selling any infinite year block (IYB) RTCs must provide the Executive Officer a~~

~~written statement that there is no intention to shut down the facility. For the purpose of this rule, IYB refer to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years. This will provide staff assurance that the trade in question is not related to a permanent shutdown.~~

~~It is proposed that any Facility Permit Holder of a facility listed in Table 7 or 8 in Rule 2002 that is permanently shutting down some or all equipment with emissions greater than or equal to 25 percent of the facility emissions for any quarter within the previous 2 compliance years must surrender:~~

- ~~NOx RTCs to the District for retirement from the RECLAIM Program; and~~
- ~~the permit(s) for the equipment that is shutdown.~~

Starting (*date of amendment*) the highest ranking official of any facility listed in Table 7 or 8 selling any infinite year block (IYB) RTCs shall provide the Executive Officer a written statement that there is no current intent~~*ion*~~ to shut down the facility within the next five years. For the purpose of this rule, IYB refer to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

On or after [*2 years after date of amendment*], ~~*A*~~any Facility Permit Holder of a facility listed in Table 7 or 8 permanently shutting down ~~*some or all*~~one or more pieces of equipment with emissions greater than or equal to 25 percent of the facility's total NOx emissions for any quarter within the previous 2 compliance years shall surrender:

(A) NOx RTCs as determined under paragraph (i)(3) to the District for retirement from the RECLAIM Program; and

(B) the permit(s) for the equipment that is shutdown.

It should be noted that equipment will be deemed shut down and subject to the RTC and permit surrender requirements if it is non-operational for a period of two consecutive years or longer, unless the subject equipment is used in a cyclical operation with a cyclic period of two or more years. The reasons for non-operation cannot be attributed to economic circumstances.

The NOx RTCs to be surrendered must include those valid for all compliance years starting from the compliance year after the shutdown occurs and be equal to the NOx Allocations issued by the District to the facility multiplied by the maximum quarterly ratio in the previous 2 years. For the purposes of this rule, each quarterly ratio shall be calculated as follows:

$$Quarterly\ Ratio = \frac{Quarterly\ NOx\ emissions\ from\ the\ shutdown\ equipment}{Total\ \ facility\ \cancel{certified}\ quarterly\ NOx\ emissions\ for\ the\ same\ quarter}$$

The requirements related to the abovementioned facility and equipment shutdowns would not apply to shutdown equipment for which the equipment's operational capacity is replaced by new or existing equipment serving the same functional needs at the same facility or another facility under common control.

Notwithstanding the requirements of Rule 204, the Executive Officer shall notify the Facility Permit Holder 60 days prior to re-issuing the Facility Permit to reflect removal of the shutdown equipment from the Facility Permit.

Rule 2005

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state NSR program requirements. Rule 2005 provides three separate requirements to meet the NSR programmatic equivalency:

1) Sources causing emission increases must be equipped with Best Available Control Technology (BACT),

2) Modeling must be used to demonstrate that operation of the source will not result in a significant increase in the air quality concentration of nitrogen dioxide (NO_2) if the facility total emissions exceed its 1994 starting allocations plus non-tradable credits, and

3) The facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter.

These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. The evaluation of emission increases under this paragraph is defined on a device-by-device basis at the maximum potential to emit. Any time a new NOx- (or SOx)-emitting RECLAIM device is installed, it triggers the credit holding requirements because it does not have any prior emissions, even in cases where the new device is replacing an older, dirtier device.

Among these requirements, the credit holding requirement ensures that the facility has adequate credits to offset emission increases year-by-year. It does not directly require emission decreases. On the other hand, all RECLAIM facilities are required to reconcile their Allocations to their emissions (i.e. hold enough RTCs to cover their emissions) by the end of each quarter and each compliance year pursuant to Rule 2004 – Requirements. Therefore, under RECLAIM, all facilities are required to have credits to offset all RECLAIM emissions regardless if they are subject to the requirements of Rule 2005.

The amendments made in June 3, 2011 required an existing RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but will not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits.

The offset requirements for new RECLAIM facilities remained unchanged. Thus a new facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any unused RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter.

To help in remedying this holding requirement for new ~~electrical~~ electricity generating facilities that cannot change their allowable NOx emissions in their Facility Permit, staff is proposing a Regional NSR Holing Account in Rule 2002. Proposed changes in Rule 2005 would assure that the Regional NSR Holing Account would be used the for the purpose of complying with the NSR requirements.

Other Administrative Amendments

Besides the changes described in Rule 2002 and 2005 above, staff also proposes administrative amendments to Regulation XX to clarify the rule language and to ensure effective and consistent implementation of the RECLAIM program.

Rule 2002(b) - 5-Year Limitation on Amending Annual Emission Reports

Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) specifies the procedures for quantifying RECLAIM allocations for facilities in the original (1994) RECLAIM universe, facilities electing to enter the program, and facilities included into the program because they experienced actual NOx or SOx emissions of four tons or more in a year. Allocations are quantified by multiplying throughput levels (*e.g.*, quantity of fuel consumed or of material processed) documented in peak year Annual Emission Reports (AERs), by emission factors specified in Rule 2002. However, if the emission factors used in preparing the peak year AER reports are lower than those in Rule 2002, then the lower factors are to be used for quantifying allocations.

Some facilities entering the RECLAIM program have sought to amend their past AERs, which dated as far back as 1989, in ways that increase the initial SOx and/or NOx allocations quantified for them pursuant to Rule 2002. The longer the time elapsed between the reporting period and submittal of the correction the more problematic the process of validating the proposed corrections and their supporting documentation becomes. In fact, such validation has been infeasible in some cases. Therefore, staff is proposing to add paragraph (b)(5) to Rule 2002 specifying that the Executive Officer will not consider any AER data submitted five years beyond the original due date when calculating a facility's allocation. This language would provide clarity to RECLAIM facilities and potential RECLAIM facilities regarding what AR submittals and/or revisions may be considered in determining their allocations, as well as relieve the costs, both financial and in terms of staff resources, associated with review and validation of AER submittals made long after the reporting periods for which they are submitted.

Rule 2002 (Table 4) – Minor Typographical Edit

Rule 2002's Table 4 – RECLAIM SOx Tier III Emission Standards includes a row for Diesel Combustion, which includes a BARCT Emission Standard of "15 ppmv as required under Rule 431.2." However, the standard in Rule 431.2 is actually "15 ppm by weight" rather than 15 ppmv (*i.e.*, 15 ppm by volume). The staff proposal would correct the Table 4 entry to "15 ppm by weight as required under Rule 431.2," consistent with the definition of Low Sulfur Diesel at Rule 431.2(b)(5).

Rules 2011 and 2012 - Delayed RATA Tests due to Extenuating Circumstances

Rules 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions set forth monitoring, reporting, and recordkeeping requirements for sources of SOx and NOx at RECLAIM facilities. The accompanying Appendices A to these rules, Rule 2011 – Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and Rule 2012 – Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, outline in greater detail the technical specifications required for monitoring, reporting, and recordkeeping for RECLAIM sources. Moreover, Attachment C, Subdivision B, Paragraph 2 of Appendix A of both these protocols, sets forth the timing and frequency of Semi-Annual Assessments in the form of Relative Accuracy Test Audits (RATAs) for RECLAIM Continuous Emission Monitoring Systems (CEMS). For instance, SOx and NOx equipment monitored by CEMS are required to perform RATAs on a semi-annual basis within six months of the end of the calendar quarter in which the CEMS last passed such a test. Such RATAs may be performed on an annual basis, provided that the relative accuracies of the SOx (NOx) pollutant concentration monitor, flow monitoring system, and the SOx (NOx) emission rate measurement system measured during the previous audit are 7.5% or less. These stringent testing requirements help ensure the accuracy of the CEMS in monitoring SOx and NOx emissions.

RATAs are conducted while the equipment is in operation. Equipment monitored by CEMS at some RECLAIM facilities, however, may experience extenuating circumstances that prevent them from conducting RATA tests in a timely manner. For instance, a major source may experience unforeseen equipment failure that renders it inoperable. Under such unforeseen events, the equipment cannot be made operational to conduct a RATA.

Additionally, facilities under contract with the California Independent System Operator (CalISO), as well as ~~electrical~~ electricity generating facilities owned and operated by municipalities, have experienced difficulties in meeting RATA deadlines because their equipment operates based on current energy demand and may not operate long enough (or at all) to conduct a RATA in the quarter in which the RATA is due. In contrast, most facilities typically require their major sources to be continually operational, used on a regular basis, and able to conduct a timely RATA for their equipment. In the event that their equipment is not in operation, the facility has the option of seeking a variance or filing an application for non-operational status to avoid violating the RATA requirement since sources permitted as non-operational are not required to conduct RATAs. However, ~~electrical~~ electricity generating facilities with equipment under contract with CalISO or owned and operated by municipalities often do not know when demand for electricity will result in generation equipment being required to operate until a day prior, creating scheduling difficulties in conducting RATAs and precluding the use of non-operational status. The inherent inconsistent operational nature of such equipment at electric generating facilities sometimes causes a need to postpone their RATAs.

Under current rule requirements, facilities having such extenuating circumstances seek variances for indeterminate amounts of time. The proposed amendments would, under specific conditions, allow RECLAIM Facility Permit Holders of equipment experiencing these extenuating circumstances to postpone RATAs. In the case of unforeseen equipment failure, Facility Permit Holders would have the option to postpone RATAs for this equipment to no more than 14 operating days after recommencing operation of the repaired equipment. Concerns were expressed that 14 operating days may not be sufficient in cases of sequential failures of the same equipment. However, the proposed 14 operating day RATA postponement for unforeseen equipment failure would apply separately for each unrelated, independent event. As such, if equipment operating under the 14 day RATA postponement provision should experience an unrelated failure prior to successfully completing a RATA, the 14 day clock would restart. On the other hand, if the same failure should recur in a similar situation, the 14 day clock would continue running and would not be reset. In the case of ~~electrical~~ electricity generating facilities under contractual obligation with CalISO to have equipment available or owned and operated by municipalities that did not operate long enough to conduct a RATA during the quarter in which it is due, the semi-annual or annual assessment could be postponed to the next calendar quarter provided the follow criteria are met:

- The RATA was scheduled for the first 45 days of the calendar quarter in which it is due, but the equipment's operating schedule prevents completion of the RATA; and

- A passing Cylinder Gas Audit is conducted during the calendar quarter in which the RATA is due.

Paragraph 2, Subdivision B, Attachment C, of Appendix A to both Rule 2011 and Rule 2012 establishes both the timeline and the frequency for Semi-Annual Assessments to be performed for equipment monitored by CEMS. The purpose of these stringent testing requirements is to ensure the accuracy of the CEMS in monitoring SOx and NOx emissions. These Semi-Annual Assessments obligate facility permit holders to conduct RATAs within six months of the end of the calendar quarter in which the CEMS was last tested. Alternatively, such RATAs may be performed on an annual basis, provided that the relative accuracies of the SOx (NOx) pollutant concentration monitor, flow monitoring system, and the SOx (NOx) emission rate measurement systems are all 7.5% or less. Furthermore, for CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments may be delayed until no later than 14 operating days after emissions pass through the stack/duct. Some RECLAIM facilities that have had to disconnect their equipment due to failures and remove it off-site for repair have requested to have their RATA due dates extended. Other RECLAIM facilities, specifically ~~electrical~~ electricity generating facilities that either have contractual agreements with CalISO to have their equipment available but not necessarily operating or are owned and operated by municipalities, have requested to delay their RATA testing until they have sufficient operating hours to conduct a RATA. Staff proposes to revise Attachment C. B.2. of Appendix A in both Rules 2011 and 2012 by adding subparagraphs (c) and (d), to allow RATA postponements due to these extenuating circumstances. For facilities that have major sources that are physically unable to operate to conduct a RATA, postponement of the RATA due date to within 14 unit operating days from the first re-firing of the major source is proposed to be allowed only if the following requirements are met:

- All fuel feed lines to the major source are either disconnected or opened and flanges are placed at both ends of the disconnected or opened lines, and

- The fuel meter(s) for the disconnected or opened fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

There were concerns from operators that for some units, disconnecting the fuel feed lines was not feasible. Alternatively, an operator can open the fuel strainers to accomplish the same goal. That is, with the strainers open it would be possible for enforcement staff to get visual confirmation that no fuel is flowing to the units. For any hour that fuel flow records are not available to verify no fuel flow, SOx (NOx) emissions would be required to be calculated using the maximum valid hourly emissions from the last 30 days of operation. Additionally, prior to equipment restart the Facility Permit Holder would be required to:

- provide written notification to the District no later than 72 hours prior to starting up the major source;
- start the CEMS no later than 24 hours prior to the start-up of the major source; and
- conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source.

CEMS emissions data after the re-start of operations would only be considered valid if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data would be considered invalid until the semi-annual or annual assessment is performed and passed. For such invalid CEMS emissions data, SOx (NOx) emissions would be calculated using the maximum valid hourly emissions from the last 30 days of operation, commencing with the hour of startup and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

For ~~electrical~~ electricity generating facilities either having contractual agreements with CalISO to have their major source available but not necessarily operating, yet not having sufficient hours to conduct RATA testing or owned and operated by a municipality, amended rule language is being proposed to allow the postponement of the semi-annual or annual assessment to the next calendar quarter, provided that the facility demonstrates:

- the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and
- a Cylinder Gas Audit (CGA) is conducted and passed within the calendar quarter when the assessment is due.

Rules 2011 and 2012 - Typographical Edits

The staff proposal would, if adopted, also make the following typographical clarifications and corrections:

- Under Rules 2011 and 2012 Appendix A, Attachment C B.2.b the word "unit" would be added to offer clarity regarding the time period for RATAs that are conducted on equipment for which no emissions have passed through any stack or duct in two or more successive quarters;

- The rule language "Proposed" and "Draft" found in Rule 2011 Appendix A, Attachment C B.2.e., which inadvertently had been left in the previous amended rules, would now be deleted;

- Rule language found in subparagraph (e) of Rule 2012 Appendix A, Attachment C B.2, referencing "Chapter 2, Subdivision B, Paragraph 10, Chapter 2, Subdivision B, Paragraph 11, and Chapter 2, Subdivision B, Paragraph 12" would be replaced with "Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 18", to clarify relative accuracy requirements for fuel flow measuring devices; and

- Rule language found in subparagraph (e) of Rule 2011 Appendix A, Attachment C B.2 referencing "Chapter 2, Subdivision B, Paragraphs 10, 11, and 12…" would be replaced with "Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 13…" to clarify the relative accuracy requirements for analyzers.

Proposed Amended Rules 2011, Appendix A, Attachment E and 2012, Appendix A, Attachment F – *Clarification of "Standard Gas Conditions"*

Standard Gas Conditions is defined in Rule 2011, Appendix A, Attachment E and Rule 2012, Appendix A, Attachment F as "a temperature of 68 ºF and one atmosphere of pressure." Rule 102 – Definition of Terms, on the other hand, defines standard conditions for SCAQMD purpose of SCAQMD purposes other than RECLAIM as "a gas temperature of 60 ºF and a gas pressure of [1 atmosphere]." Similarly, the natural gas industry uses standard conditions of 60 ºF and one atmosphere. Many gas meters, including those used by natural gas utilities for billing purposes, automatically correct their readings to 60 ºF and one atmosphere. As such, many RECLAIM facility operators need to convert their meter readings from the 60 ºF and one atmosphere standard to the 68 ºF and one atmosphere standard. While this conversion is quite simple (multiplication by a constant factor of 1.015), it sometimes causes confusion for facility operators, particularly for those with facilities where some, but not all, of the gas meters are corrected to 60 ºF and others are uncorrected. It also makes the correction slightly more complicated for facilities with uncorrected meters simply because standard tables are readily available for converting from actual conditions to the 60 ºF standard but not to the 68 ºF standard. The proposed amendments to Rule 2011, Appendix A, Attachment E and 2012 Appendix A, Attachment F would resolve this situation by giving each facility the operator the option to either the 60 ºF standard or the 68 ºF standard provided one or the other is used consistently throughout the facility for RECLAIM purposes.

Appendix Y – RTC Holdings as of September 22, 2015

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
136	PRESS FORGE CO	3.6	0.01
346	FRITO-LAY, INC.	15.2	0.04
550	LA CO., INTERNAL SERVICE DEPT	17.6	0.05
710	TEXACO EXPLORATION & PRODUCTION INC.	2.0	0.01
1073	BORAL ROOFING LLC	24.2	0.07
1744	KIRKHILL - TA COMPANY	1.2	0.00
2083	SUPERIOR INDUSTRIES INTERNATIONAL INC	0.1	0.00
2418	FRUIT GROWERS SUPPLY CO	1.9	0.01
2825	MCP FOODS INC	2.2	0.01
2912	HOLLIDAY ROCK CO INC	1.6	0.00
2946	PACIFIC FORGE INC	2.5	0.01
3029	MATCHMASTER DYEING & FINISHING INC	3.8	0.01
3417	AIR PROD & CHEM INC	15.1	0.04
3585	R. R. DONNELLEY & SONS CO, LA MFG DIV	4.2	0.01
3704	ALL AMERICAN ASPHALT, UNIT NO.01	14.5	0.04
3721	DART CONTAINER CORP OF CALIFORNIA	3.5	0.01
3968	TABC, INC	28.0	0.08
4242	SAN DIEGO GAS & ELECTRIC	48.3	0.13
4477	SO CAL EDISON CO	68.7	0.19
5973	SO CAL GAS CO	30.3	0.08
5998	ALL AMERICAN ASPHALT	1.4	0.00
7411	DAVIS WIRE CORP	2.4	0.01
7416	PRAXAIR INC	8.0	0.02
7427	OWENS-BROCKWAY GLASS CONTAINER INC	50.0	0.14
8439	EXXON MOBIL CORP	3.8	0.01
8547	QUEMETCO INC	24.4	0.07
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	27.2	0.07
9053	VEOLIA ENERGY LOS ANGELES, INC	7.2	0.02
9755	UNITED AIRLINES INC	0.8	0.00
10141	ANGELICA TEXTILE SERVICES	2.0	0.01
11034	VEOLIA ENERGY LOS ANGELES, INC	8.2	0.02
11119	THE GAS CO./ SEMPRA ENERGY	0.9	0.00
11142	KEYSOR-CENTURY CORP	1.7	0.00
11435	PQ CORPORATION	24.9	0.07
11716	FONTANA PAPER MILLS INC	4.7	0.01
11887	NASA JET PROPULSION LAB	21.4	0.06
12155	ARMSTRONG WORLD INDUSTRIES INC	1.2	0.00
12372	MISSION CLAY PRODUCTS	3.7	0.01
12428	NEW NGC, INC.	15.0	0.04
12912	LIBBEY GLASS INC	0.0	0.00
13179	CRESCENT CRANES INC	0.2	0.00
14049	MARUCHAN INC	1.5	0.00
14092	CPC INTERNATIONAL INC, BEST FOODS DIV	1.3	0.00
14495	VISTA METALS CORPORATION	15.4	0.04
14502	CITY OF VERNON, VERNON GAS & ELECTRIC	2.1	0.01
14736	THE BOEING COMPANY	1.4	0.00

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
14871	SONOCO PRODUCTS CO	2.4	0.01
14926	SEMPRA ENERGY (THE GAS CO)	2.9	0.01
14944	CENTRAL WIRE, INC.	3.5	0.01
15381	CHEVRON USA INC	1.5	0.00
15504	SCHLOSSER FORGE COMPANY	10.9	0.03
16338	KAISER ALUMINUM FABRICATED PRODUCTS, LLC	4.8	0.01
16352	SO CAL EDISON CO	7.0	0.02
16639	SHULTZ STEEL CO	18.6	0.05
16642	ANHEUSER-BUSCH LLC., (LA BREWERY)	21.5	0.06
16660	THE BOEING COMPANY	2.2	0.01
16978	CLOUGHERTY PACKING LLC/HORMEL FOODS CORP	4.5	0.01
17344	EXXONMOBIL OIL CORP	1.8	0.00
17623	LOS ANGELES ATHLETIC CLUB	0.8	0.00
17953	PACIFIC CLAY PRODUCTS INC	42.6	0.12
17956	WESTERN METAL DECORATING CO	0.7	0.00
18294	NORTHROP GRUMMAN SYSTEMS CORP	16.9	0.05
18455	ROYALTY CARPET MILLS INC	2.7	0.01
18931	TAMCO	73.7	0.20
19167	R J. NOBLE COMPANY	7.1	0.02
19390	SULLY-MILLER CONTRACTING CO.	3.0	0.01
19989	PARKER HANNIFIN AEROSPACE CORP	0.1	0.00
20203	RECYCLE TO CONSERVE INC.	1.4	0.00
20543	REDCO II	0.9	0.00
20604	RALPHS GROCERY CO	2.9	0.01
21598	ANGELICA TEXTILE SERVICES	1.8	0.00
21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	8.7	0.02
22603	EXXONMOBIL PRODUCTION COMPANY	3.7	0.01
22607	CALIFORNIA DAIRIES, INC	4.1	0.01
22911	CARLTON FORGE WORKS	3.8	0.01
23752	AEROCRAFT HEAT TREATING CO INC	3.6	0.01
25058	EXXONMOBIL OIL CORP	1.8	0.00
25638	BURBANK CITY, BURBANK WATER & POWER	36.8	0.10
35302	OWENS CORNING ROOFING AND ASPHALT, LLC	4.3	0.01
36909	LA CITY, DEPARTMENT OF AIRPORTS	4.5	0.01
37603	SGL TECHNIC INC, POLYCARBON DIVISION	2.2	0.01
38440	COOPER & BRAIN - BREA	0.0	0.00
38872	MARS PETCARE U.S., INC.	4.1	0.01
40034	BENTLEY PRINCE STREET INC	4.2	0.01
40483	NELCO PROD. INC	1.4	0.00
42079	ROD'S FOOD PRODUCTS	0.4	0.00
42630	PRAXAIR INC	2.8	0.01
42775	WEST NEWPORT OIL CO	2.0	0.01
43201	SNOW SUMMIT INC	68.5	0.19
43436	TST, INC.	18.9	0.05
45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	12.7	0.03
46268	CALIFORNIA STEEL INDUSTRIES INC	160.5	0.44
47781	OLS ENERGY-CHINO	17.4	0.05
50098	D&D DISPOSAL INC,WEST COAST RENDERING CO	1.5	0.00

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
14871	SONOCO PRODUCTS CO	2.4	0.01
14926	SEMPRA ENERGY (THE GAS CO)	2.9	0.01
14944	CENTRAL WIRE, INC.	3.5	0.01
51620	WHEELABRATOR NORWALK ENERGY CO INC	31.0	0.09
52517	REXAM BEVERAGE CAN COMPANY	11.1	0.03
53729	TREND OFFSET PRINTING SERVICES, INC	2.2	0.01
54402	SIERRA ALUMINUM COMPANY	7.2	0.02
56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	4.8	0.01
58622	LOS ANGELES COLD STORAGE CO	0.2	0.00
59618	PACIFIC CONTINENTAL TEXTILES, INC.	1.9	0.01
60531	PACIFIC FABRIC FINISHING	1.1	0.00
61722	RICOH ELECTRONICS INC	1.7	0.00
61962	LA CITY, HARBOR DEPT	3.2	0.01
62548	THE NEWARK GROUP, INC.	4.6	0.01
63180	DARLING INTERNATIONAL INC	7.5	0.02
68042	CORONA ENERGY PARTNERS, LTD	12.7	0.03
68118	TIDELANDS OIL PRODUCTION COMPANY ETAL	2.9	0.01
73022	US AIRWAYS INC	0.7	0.00
74424	ANGELICA TEXTILE SERVICES	1.3	0.00
83102	LIGHT METALS INC	7.0	0.02
84223	NEWELLRUBBERMAID INC	0.8	0.00
85943	SIERRA ALUMINUM COMPANY	4.3	0.01
89248	OLD COUNTRY MILLWORK INC	1.4	0.00
94872	METAL CONTAINER CORP	12.1	0.03
94930	CARGILL INC	0.9	0.00
95212	FABRICA	4.7	0.01
96587	TEXOLLINI INC	0.4	0.00
97081	THE TERMO COMPANY	0.9	0.00
99588	DOMTAR GYPSUM INC	7.5	0.02
101337	NATIONAL OFFSETS	0.3	0.00
101656	AIR PRODUCTS AND CHEMICALS, INC.		
101977	SIGNAL HILL PETROLEUM INC	4.5	0.01
105277	SULLY MILLER CONTRACTING CO	2.6	0.01
105903	PRIME WHEEL	0.7	0.00
107653	CALMAT CO	1.3	0.00
107654	CALMAT CO	2.7	0.01
107655	CALMAT CO	9.5	0.03
107656	CALMAT CO	2.9	0.01
113160	HILTON COSTA MESA	1.8	0.00
114264	ALL AMERICAN ASPHALT	3.3	0.01
115172	RAYTHEON COMPANY	2.1	0.01
115241	THE BOEING COMPANY	4.8	0.01
115277	LAFAYETTE TEXTILE IND LLC	0.0	0.00
115314	LONG BEACH GENERATION, LLC	43.2	0.12
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	132.1	0.36
115389	AES HUNTINGTON BEACH, LLC	89.9	0.25
115394	AES ALAMITOS, LLC	273.0	0.75
115449	PLAYA PHASE I COMMERCIAL LAND, LLC	0.0	0.00
115536	AES REDONDO BEACH, LLC	147.0	0.40
115563	NCI GROUP INC., DBA, METAL COATERS OF CA	1.0	0.00
115663	EL SEGUNDO POWER, LLC	247.8	0.68
117140	AOC, LLC	2.0	0.01

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
14871	SONOCO PRODUCTS CO	2.4	0.01
14926	SEMPRA ENERGY (THE GAS CO)	2.9	0.01
14944	CENTRAL WIRE, INC.	3.5	0.01
51620	WHEELABRATOR NORWALK ENERGY CO INC	31.0	0.09
52517	REXAM BEVERAGE CAN COMPANY	11.1	0.03
53729	TREND OFFSET PRINTING SERVICES, INC	2.2	0.01
54402	SIERRA ALUMINUM COMPANY	7.2	0.02
56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	4.8	0.01
58622	LOS ANGELES COLD STORAGE CO	0.2	0.00
59618	PACIFIC CONTINENTAL TEXTILES, INC.	1.9	0.01
60531	PACIFIC FABRIC FINISHING	1.1	0.00
61722	RICOH ELECTRONICS INC	1.7	0.00
117227	SHCI SM BCH HOTEL LLC, LOEWS SM BCH HOTE	1.5	0.00
117290	B BRAUN MEDICAL, INC	7.8	0.02
118406	CARSON COGENERATION COMPANY		
118618	UNI-PRESIDENT (U.S.A.) INC	1.1	0.00
119134	ITW CIP CALIFORNIA	0.0	0.00
119596	SNAK KING CORPORATION	4.2	0.01
123774	HERAEUS PRECIOUS METALS NO. AMERICA, LLC	4.7	0.01
124619	ARDAGH METAL PACKAGING USA INC.	0.7	0.00
124723	GREKA OIL & GAS, INC	0.5	0.00
124808	INEOS POLYPROPYLENE LLC	2.0	0.01
124838	EXIDE TECHNOLOGIES		
125579	DIRECTV	0.0	0.00
126498	STEELSCAPE, INC	14.2	0.04
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	25.2	0.07
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49.0	0.13
129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	10.1	0.03
129816	INLAND EMPIRE ENERGY CENTER, LLC		
130211	PAPER-PAK INDUSTRIES	6.3	0.02
131850	SHAW DIVERSIFIED SERVICES INC	7.6	0.02
132068	BIMBO BAKERIES USA INC	3.2	0.01
133405	BODYCOTE THERMAL PROCESSING	2.3	0.01
137471	GRIFOLS BIOLOGICALS INC	6.0	0.02
137508	TONOGA INC, TACONIC DBA	1.5	0.00
138568	CALIFORNIA DROP FORGE, INC	0.9	0.00
139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	14.7	0.04
141555	CASTAIC CLAY PRODUCTS, LLC	14.0	0.04
142267	FS PRECISION TECH LLC	1.2	0.00
142536	DRS SENSORS & TARGETING SYSTEMS, INC	0.1	0.00
143738	DCOR LLC	1.1	0.00
143739	DCOR LLC	0.2	0.00
143740	DCOR LLC	8.8	0.02
143741	DCOR LLC	3.5	0.01
144455	LIFOAM INDUSTRIES, LLC	0.7	0.00
146536	WALNUT CREEK ENERGY, LLC	57.5	0.16
148340	THE BOEING CO. COMMERCIAL AVIATION SRVCS	6.8	0.02
148896	VINTAGE PRODUCTION CALIFORNIA LLC	1.2	0.00
148897	VINTAGE PRODUCTION CALIFORNIA LLC	0.8	0.00
148925	CHERRY AEROSPACE	1.8	0.00
149491	BOEING REALTY CORP		

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
151394	LINN OPERATING INC	0.1	0.00
151415	LINN WESTERN OPERATING, INC	0.0	0.00
151532	LINN OPERATING, INC	7.8	0.02
151594	OXY USA, INC	2.8	0.01
151798	TESORO REFINING AND MARKETING CO, LLC	49.6	0.14
151899	VINTAGE PRODUCTION CALIFORNIA LLC	1.9	0.01
152054	LINN WESTERN OPERATING INC	0.0	0.00
152501	PRECISION SPECIALTY METALS, INC.	1.8	0.00
152707	CPV SENTINEL LLC	120.5	0.33
153033	GEORGIA-PACIFIC CORRUGATED LLC	0.6	0.00
153199	THE KROGER CO/RALPHS GROCERY CO	1.8	0.01
153992	CANYON POWER PLANT	42.0	0.12
155221	SAVE THE QUEEN LLC (DBA QUEEN MARY)	1.1	0.00
155474	BICENT (CALIFORNIA) MALBURG LLC	26.9	0.07
155877	MILLERCOORS, LLC	21.9	0.06
156722	AMERICAN APPAREL KNIT AND DYE	3.7	0.01
156741	HARBOR COGENERATION CO, LLC	20.9	0.06
157359	HENKEL ELECTRONIC MATERIALS, LLC	0.9	0.00
157363	INTERNATIONAL PAPER CO	1.5	0.00
158300	CITY OF ONTARIO	2.8	0.01
160437	SOUTHERN CALIFORNIA EDISON	144.8	0.40
161300	SAPA EXTRUDER, INC	5.7	0.02
164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	9.2	0.03
165192	TRIUMPH AEROSTRUCTURES, LLC	2.8	0.01
166073	BETA OFFSHORE		
168088	PCCR USA	2.4	0.01
169514	TITAN TERMINAL AND TRANSPORT INC	0.0	0.00
169678	ITT CANNON, LLC	0.3	0.00
169754	SO CAL HOLDING, LLC	104.4	0.29
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	584.4	1.60
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	139.7	0.38
172005	NEW- INDY ONTARIO, LLC	65.2	0.18
172077	CITY OF COLTON	16.4	0.04
173904	LAPEYRE INDUSTRIAL SANDS, INC	4.3	0.01
174406	ARLON GRAPHICS LLC	1.3	0.00
174544	BREITBURN OPERATING LP	2.4	0.01
174591	TESORO REF & MKTG CO LLC,CALCINER	133.7	0.37
174655	TESORO REFINING & MARKETING CO, LLC	839.0	2.30
175124	AEROJET ROCKETDYNE OF DE, INC.	1.6	0.00
175154	FREEPORT-MCMORAN OIL & GAS	2.5	0.01
175191	FREEPORT-MCMORAN OIL & GAS	9.4	0.03
176708	ALTAGAS POMONA ENERGY INC.	15.5	0.04
178639	ECO SERVICES OPERATIONS LLC	26.0	0.07
179137	QG PRINTING II CORP	0.6	0.00
179957	CA LOS ANGELES TIMES SQUARE LLC	2.6	0.01
180367	LINN OPERATING INC	39.9	0.11
180410	REICHHOLD LLC 2	1.4	0.00
700050	KEN BARKER	1.5	0.00
700084	SHELL NORTH AMERICA (US), L.P.	2.5	0.01
700126	GENERAL ELECTRIC COMPANY	113.3	0.31
700144	OLDUVAI GORGE, LLC	27.8	0.08
700161	KOCH SUPPLY & TRADING, LP	85.9	0.24

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
700170	ABATEMENT CAPITAL LLC	20.2	0.06
700177	GREY EPOCH LLC	2.0	0.01
800003	HONEYWELL INTERNATIONAL INC	2.7	0.01
800016	BAKER COMMODITIES INC	9.3	0.03
800026	ULTRAMAR INC	561.4	1.54
800030	CHEVRON PRODUCTS CO.	1,289.1	3.53
800037	DEMENNO/KERDOON	4.6	0.01
800038	THE BOEING COMPANY - C17 PROGRAM	13.7	0.04
800042	ECO PETR INC (EIS USE ONLY)	0.6	0.00
800066	HITCO CARBON COMPOSITES INC	8.7	0.02
800067	THE BOEING COMPANY	2.2	0.01
800074	LA CITY, DWP HAYNES GENERATING STATION	189.5	0.52
800075	LA CITY, DWP SCATTERGOOD GENERATING STN	179.1	0.49
800080	LUNDAY-THAGARD COMPANY	18.1	0.05
800088	3M COMPANY	14.2	0.04
800089	EXXONMOBIL OIL CORPORATION	900.9	2.47
800094	EXXONMOBIL OIL CORPORATION	2.0	0.01
800099	NORRIS IND (EIS USE)	0.3	0.00
800110	THE BOEING COMPANY	1.3	0.00
800113	ROHR, INC.	8.6	0.02
800127	SO CAL GAS CO	41.6	0.11
800128	SO CAL GAS CO	179.7	0.49
800129	SFPP, L.P.	6.3	0.02
800149	US BORAX INC	4.2	0.01
800150	US GOVT, AF DEPT, MARCH AIR RESERVE BASE	7.4	0.02
800153	US GOVT, NAVY DEPT LB SHIPYARD	25.7	0.07
800168	PASADENA CITY, DWP	29.5	0.08
800170	LA CITY, DWP HARBOR GENERATING STATION	20.1	0.06
800181	CALIFORNIA PORTLAND CEMENT CO	1.5	0.00
800182	RIVERSIDE CEMENT CO	1.1	0.00
800183	PARAMOUNT PETR CORP	68.6	0.19
800189	DISNEYLAND RESORT	53.0	0.15
800193	LA CITY, DWP VALLEY GENERATING STATION	40.6	0.11
800196	AMERICAN AIRLINES INC	2.9	0.01
800205	BANK OF AMERICA NT & SA, BREA CENTER	1.6	0.00
800210	CONEXANT SYSTEMS INC	1.6	0.00
800253	UNION CARBIDE CORP	0.1	0.00
800264	EDGINGTON OIL COMPANY	17.0	0.05
800310	TA INDUSTRIES INC	0.5	0.00
800325	TIDELANDS OIL PRODUCTION CO	8.7	0.02
800330	THUMS LONG BEACH	2.6	0.01
800335	LA CITY, DEPT OF AIRPORTS	16.8	0.05
800337	CHEVRON U.S.A., INC (NSR USE)	8.8	0.02
800338	SPECIALTY PAPER MILLS INC	2.4	0.01
800342	ARTESIA KNITS INC	1.6	0.00
800344	CALIFORNIA AIR NATIONAL GUARD, MARCH AFB	0.7	0.00

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
800371	RAYTHEON SYSTEMS COMPANY - FULLERTON OPS	2.3	0.01
800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	16.4	0.04
800373	LAKELAND DEVELOPMENT COMPANY	0.0	0.00
800393	VALERO WILMINGTON ASPHALT PLANT	5.3	0.01
800408	NORTHROP GRUMMAN SYSTEMS	6.8	0.02
800409	NORTHROP GRUMMAN SYSTEMS CORPORATION	12.8	0.03
800416	PLAINS WEST COAST TERMINALS LLC	0.4	0.00
800417	PLAINS WEST COAST TERMINALS LLC	2.5	0.01
800419	PLAINS WEST COAST TERMINALS LLC	0.3	0.00
800420	PLAINS WEST COAST TERMINALS LLC	1.8	0.00
800436	TESORO REFINING AND MARKETING CO, LLC	667.9	1.83
	TOTAL (TONS PER DAY)		**26.5**

Appendix Z – Comment Letters Received and Responses to Comments

The Public Workshop for RECLAIM was held on July 22, 2015. Comment letters received on and after that date are responded to below. Over the three year rule development process, many other letters, emails, and verbal comments have been received. These comments helped the rule proposal evolve, and staff appreciates all the stakeholder input.

More recent comment letters have been numbered and individual comments within each letter have been bracketed and numbered. Following each comment letter is staff's responses to the individual comments.

Comment Letter #1	WSPA's letter dated August 21, 2015, Phillips66 letter dated August 21, 2015

In addition to the letters above, the following comment letters were received from July 22 to August 10, 2015. The comments from these letters and staff responses are summarized in this Appendix, followed by an attachment that includes these comment letters.

Comment Letter #2	Norton Engineering letter dated August 10, 2015
Comment Letter #3	Norton Engineering letter dated September 4, 2015
Comment Letter #4	Industry Coalition letter dated August 21, 2015
Comment Letter #5	Latham & Watkins letter dated August 20, 2015
Comment Letter #6	Yorke Engineering, LLC letter dated August 21, 2015
Comment Letter #7	Charles F. Timms, Jr. August 21, 2015
Comment Letter #8	SCEC letter dated August 26, 2015
Comment Letter #9	Eco Services letter dated August 28, 2015
Comment Letter #10	Charles F. Timms, Jr. dated September 17, 2015
Comment Letter #11	Southern California Edison (no date)
Comment Letter #12	Inland Empire Energy Center – GE Capital dated September 22, 2015
Comment Letter #13	Earth Justice dated July 8, 2014
Comment Letter #14	Arnie Smith email dated August 11, 2015
Comment Letter #15	Karl Lany email dated August 20, 2015
Comment Letter #16	George Piantka email dated August 14, 2015
Comment Letter #17	Chuck Casey email dated September 24, 2015

Comment Letter #1 – WSPA's Letter and Phillips 66's Letter Dated August 21, 2015

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Sue Gornick
Senior Coordinator, Southern California Region

VIA ELECTRONIC MAIL

August 21, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: WSPA COMMENTS ON PRELIMINARY DRAFT STAFF REPORT (PDSR) FOR NOX RECLAIM AMENDMENTS DATED JULY 21, 2015

Dear Dr. Fine:

1-1

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the Regional Clean Air Incentives Market (RECLAIM) program.

WSPA and the Industry RECLAIM Coalition (of which we are a member) have submitted several comment letters during this rulemaking process to request changes to the District Staff's proposal that we believe are necessary to preserve a healthy and successful RECLAIM program for all RECLAIM participants, as well as to satisfy the 2012 AQMP commitments to the State Implementation Plan (SIP) and USEPA. We have not yet received written responses to these comments. Nevertheless, we appreciate the opportunity to provide this letter to reiterate our previous concerns, and to discuss new issues arising from the PDSR.

Below are the highlights of our major concerns. More detailed comments are included in Attachment 1, attached hereto and incorporated herein by reference.

I. Shave Methodology and Arbitrary Removal of Unused RECLAIM Trading Credits (RTCs)

The District's Remaining Emissions method for calculation of RTC reductions conflicts with the CMB-01 Phase 1 and Phase 2 Control Measures as approved under the 2012 AQMP. The District's Remaining Emissions method would remove nearly all Unused RTCs from the RECLAIM market even though CMB-01 Phase 1 had explicitly considered and rejected such a reduction, instead determining that a 2 tpd reduction of Unused RTCs was more appropriate.[1] Additionally, the Incremental BARCT method proposed by the Industry RECLAIM Coalition is more consistent with Control Measure CMB-01 Phase 2 as approved under the 2012 AQMP because this method removes only those RTCs directly attributable to technology advancement (i.e., BARCT).[2]

Further, the proposed Compliance Margin of 10% may be inadequate to meet the market's historical need for Unused RTCs. Unused RTCs may be needed for several reasons, including
1-2 facility-level compliance margins, which vary depending on facility size and/or risk tolerance; RTC holding requirements imposed under Rule 2005; and market liquidity, to name a few. These Unused RTCs have historically averaged in the 15-30% range (approximately 5 to 9 tpd), with the sole exception being the RTC market crisis during the 2000 compliance year. The AQMD Staff's proposal, which includes only a 10% compliance margin, appears to be inadequate for satisfying this market requirement. Hence, WSPA recommends that Staff adopt the Incremental BARCT method as their preferred proposal.

While the proposed, limited RTC adjustment account may help certain Power Sector facilities subject to Rule 2005 New Source Review (NSR) RTC holding limit requirements, it does not resolve the holding requirements applicable to many current and future non-power facilities. It is recommended that any RTC adjustment account be accessible to all RECLAIM participants subject to the Rule 2005 NSR RTC holding requirement. WSPA also recommends that Staff provide technical justification to support the quantity of RTCs set aside to fund any such adjustment account. Finally, WSPA recommends that USEPA approval of the NSR set aside concept be obtained in writing prior to adoption of the rule amendment.

II. Shave Application and Implementation Schedule

Any NOx RECLAIM shave should be applied in an equally distributed "across-the-board" manner consistent with RECLAIM founding principles[3] and the precedent set under the 2005 NOx RECLAIM shave. In addition, the proposed schedule should be consistent with the 2012 AQMP commitment to the State Implementation Plan (SIP) which was 2 tpd in the first year; anything larger may not allow sufficient time for industry to implement emission control projects necessitated by the rulemaking.[4] Since RECLAIM is tied to BARCT (as discussed in more detail below), the lack of sufficient lead time means that the proposed shave goes beyond

[1] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.
[2] SCAQMD, 2012 AQMP. Page 4-26 states: "This phase of control is to implement periodic BARCT evaluation as required under the state law." Appendix A, page IV-A-60 presents more detailed discussion for the measure.
[3] SCAQMD, Staff Report for Proposed Amended Regulation XX – RECLAIM, January 2005, Executive Summary.
[4] WSPA-SCAQMD letter, July 14, 2015.

BARCT and that RECLAIM will not achieve equivalent or greater reductions than BARCT at equivalent or lesser cost. Therefore, the shave implementation schedule should be "back-loaded"
1-3 to accommodate a longer, more realistic project implementation period with at least 2 of the proposed 4 tpd (currently being proposed for 2016) being moved to 2019 or later. We are not recommending additional annual increments at this time, since the final shave amount has not been finalized.

III. Useful Life of Control Equipment

The proposed Useful Life of 25 years is inappropriate because AQMD rulemaking is far more frequent, with the prior major NOx RECLAIM rulemaking occurring only 10 years ago. Use of a 25 year assumption makes the rule costs appear lower than they actually are by diluting the
1-4 significant capital costs of required projects over a much longer time table than is likely to occur. The Staff analysis should be revised to reflect the 10-year Useful Life assumption, which is more consistent with recent SCAQMD rulemaking schedules and is also consistent with the Useful Life assumption typically used by CARB and other major Air Districts.

IV. BARCT Analysis

There is a statutory requirement that RECLAIM achieve equivalent or greater emission reductions than command and control at equivalent or lesser cost.

Command and Control Regulation Would Require BARCT of the Refining Sources Subject to RECLAIM: The District is required to adopt rules and regulations implementing the AQMP.[5] Among other things, these rules and regulations must require BARCT for existing sources.[6] In rulemaking addressing existing sources outside of RECLAIM, SCAQMD is mandated to require BARCT. Because of the mandate to require BARCT on all existing sources, it is fair to say that current command and control regulations and future measures adopted as part of the plan would at least be equivalent to BARCT. In the absence of a market-based mechanism (cap-and-trade program) such as RECLAIM, SCAQMD would adopt a rule requiring source-specific BARCT for each of the sources covered under RECLAIM.

1-5

The Proposed Shave Appears to Include an Additional 5.21 Tons per Day Beyond BARCT: The proposal set forth by the District indicates that the proposed BARCT would result in a reduction of 8.79 tpd of NOx from 2011 emissions at 2000/2005 BARCT. As described above, RECLAIM must achieve emission reductions equivalent to or greater than traditional command and control, or BARCT. Thus, a NOx shave equivalent to BARCT (which the District proposes at 8.79 tpd) would be the level for comparison with the Health and Safety Code provision stating that equivalent or greater reductions would be achieved at "equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment." Yet, SCAQMD does not seek merely its determined BARCT equivalency level of 8.79 tpd; it seeks 14 tpd of NOx reductions and has not demonstrated that such reductions will be achieved at equivalent or lower cost than

[5] Health & Saf. Code § 40460.
[6] Health & Saf. Code § 40440.

BARCT. The additional 5.21 tpd reduction goes above and beyond BARCT. Such a severe reduction is not essential to compliance with the statute.

SCAQMD Needs to Demonstrate that Achieving This Additional 5.21 Tons per Day Would Be Less Costly than Achieving BARCT on a Source-by-Source Basis in the District: The Health and Safety Code requires RECLAIM to achieve at least equivalent reductions as traditional command and control at an equivalent or lesser cost.[7] While the draft staff report does provide a cost accounting for BARCT, that accounting (which we believe to be understated) only covers 8.79 tons of the 14 ton per day shave. The draft staff report does not even mention, let alone provide detailed discussion of, the costs associated with the additional 5.21 tons per day being required by the proposed rule. Because the Legislature has required RECLAIM to impose costs less than or equal to command and control regulation (i.e., BARCT), and BARCT only makes up a portion of the proposed shave, the remaining reductions which are in excess of BARCT will cost more than BARCT. The costs related solely to BARCT are substantial with refinery costs over $900 million.[8] Costs associated with the additional 5.21 tpd reduction will only increase that figure in a substantial manner. The District must include the cost figures for the additional shave amount and justify imposing these reductions under the statutory standard of achieving command and control levels at equivalent or lower costs. It is simply not reasonable to exclude such a relevant factor from consideration.

V. NEC Study

1-6 The BARCT analysis for Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[9] NEC is a third-party expert hired to confirm the Staff's technical analysis in support of this rulemaking. Following the issuance of the PDSR, however, NEC responded to SCAQMD in an August 10, 2015 letter (see Attachment 2) to "clarify the most glaring misstatements/misunderstandings of the information [NEC] provided to the District." By selectively dismissing the third-party expert's findings, without resolution of the technical issues in dispute, Staff has compromised the process and the results of that process. It is unacceptable to arbitrarily reduce the overall shave by 0.85 tpd to resolve the differences in technical assumptions. For example, if the Staff disregards the conclusion from the NEC's third-party expert report, nearly 40 operating units would be impacted by this analysis error.[10] Furthermore, any adjustment that may be justified on a technical basis should be applied to the sector where the actual BARCT reduction occurs and not to the total shave reduction (i.e., Staff's proposed adjustment of 0.85 tpd should be applied to the Refinery Sector's BARCT reduction).

While WSPA understands that BARCT should represent a level of performance that is technically feasible and cost-effective for most units on a retrofit basis in a given source category, the District's assumptions regarding the feasibility of achieving the BARCT levels are

[7] Health & Saf. Code § 39616(c)(7).
[8] SCAQMD, *Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM* (Draft NOx RECLAIM Staff Report), p. 23. (July 21, 2015)
[9] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[10] SCAQMD, Preliminary Analysis – Refinery Boilers/Heaters, July 2014 (posted on AQMD website October 2014).

not supported by evidence that the units in question can achieve 2 ppm NOx. In fact, the data provided by Staff (Appendix B of the PDSR) indicates that only 4 of the 76 installed SCRs in the boiler and heater category are currently performing below 2 ppm. This alone suggests that the proposed BARCT is not representative. Even more, in a confidential WSPA refinery survey,[11] conducted by a third party contractor, only 2 of the 4 are retrofits. This does not represent the necessary proportion of the units in this source category.

The draft staff report proposes 2015 BARCT levels of 2 ppmv of NOx for FCCUs, refinery heaters and boilers greater than 40 mmbtu/hr, gas turbines, and sulfur recovery unit tail gas
1-7 incinerators. While the District justifies these levels based on an assumption that all refinery equipment can reach such levels, the draft staff report says otherwise. With respect to refinery heaters and boilers, very few of the existing refinery heaters and boilers already equipped with SCR are able to meet 2 ppmv of NOx. In fact, as stated in the draft staff report, of the 212 refinery boilers and heaters classified as major and large NOx sources, 14 heaters using refinery fuel gas have achieved 1.6-3.5 ppmv NOx, two boilers using natural gas have achieved 2-5 ppmv NOx, and a crude heater using refinery fuel gas achieved 3-8 ppmv NOx. Apart from some unknown percentage of the 14 process heaters, none of these sources already employing the control technology on which the BARCT level is based (SCR) have shown an ability to reduce emissions below 2 ppmv NOx. Accordingly, the District has not shown that a BARCT level of 2 ppmv NOx is achievable over the broad spectrum of refinery heaters and boilers subject to the proposed amendments. Therefore, 5 ppm is a more appropriate endpoint for refinery boilers/heaters.

The same is true with respect to FCCUs. The District proposes a 2015 BARCT level of 2 ppm NOx based on the ability of one FCCU achieving the proposed level. As explained by the District's consultant, of the three FCCUs currently operating with SCRs, only one of them achieves less than 2 ppmv NOx.[12] Again, achievability in one unit does not guarantee similar performance in other units, particularly units that have been operating under different conditions for many years. Each refinery has unique circumstances such as equipment type, age, and
1-8 configuration that factor into its ability to achieve the proposed emission levels. Thus, what may be achievable for one piece of equipment may not be for another. Further, while there may be controls available with the ability to achieve the proposed level of performance, such control may come at a cost that is unreasonable. The District has not shown that the proposed levels can be achieved across the board in a cost effective manner. As a result, and to be consistent with the statutory obligations, the District needs to reconsider and revise the proposed BARCT levels to ensure that they are achievable by a more representative percentage of the sources subject thereto.

VI. Costs and Cost Effectiveness

Exclusion of the NEC cost estimates results in an inappropriate minimization of the estimated Refinery Sector costs presented in the PDSR. It also inflates the presented emission reductions estimate for the Refinery Sector. The BARCT analysis should be revised to explicitly reflect the

[11] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.
[12] Norton Engineering, *Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM-SCRs for FCCUs Document No. 14-045-7* (August 10, 2015).

NEC cost estimates for Refinery Sector categories. Additionally, use of the Discounted Cash Flow (DCF) method along with interest rate and useful life assumptions make estimated costs for this rulemaking appear less expensive than they would be under the Levelized Cash Flow (LCF) method used by CARB and most other major Air Districts. WSPA believes that the LCF method is a better representation of cost effectiveness than the DCF method and recommends it be used. The same cost effectiveness threshold should be used for both DCF and LCF methods. Staff has used a higher cost threshold for LCF in the past than they used for DCF, so that the differences between the two methods are diluted.

1-9 The proposed $50,000 cost effectiveness threshold is greater than the AQMD's DCF cost effectiveness threshold for Command-and-Control sources in South Coast. Under the 2012 AQMP, the approved cost threshold for NOx control measures was $22,500 per ton,[13] and AQMD's current Best Available Control Technology (BACT) guidance document presents a cost effectiveness threshold that is only $19,100 per ton.[14] Also, the Health & Safety Code requires that market-based program costs be "equivalent or less compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment" and "the program will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment." [H&SC 39616(c)(1) and (7)]. Staff has not demonstrated that these legal obligations are satisfied. Therefore, WSPA recommends that the PDSR analysis be revised with the cost effectiveness threshold not greater than $22,500 (i.e., the cost effectiveness threshold used in the 2012 AQMP).

Further, the draft staff report understates the actual costs associated with meeting the proposed BARCT levels. As the District has done in past rulemakings, it hired NEC to provide reviews and recommendations on the analysis developed by SCAQMD as it relates to the technical feasibility of the control options as well as the cost effectiveness of each option. After gathering information from onsite visits to six of the refineries, NEC provided the District with a comprehensive evaluation of costs of each control option, the size and space needed for the equipment, and the time needed to install the control technologies. The District, however, chose to use different cost estimation approaches, opting to selectively disregard its own consultant's evaluation. This information was site specific and should be considered more credible than the
1-10 District's generic evaluation of costs. It is a hallmark of reasoned decision-making that an agency use the most accurate available information.

Apart from WSPA's concern relating to the dismissal of NEC's evaluation, the District's estimates do not include all of the costs that are required to be considered, and therefore vastly understate the cost impacts of the BARCT proposed. It appears that installation, design, and engineering costs have not been included properly. Moreover, it is critical to recognize that each refinery is unique such that BARCT levels achievable and cost effective at one refinery may not be at another. Plant configuration, equipment type, equipment age, length of time the SCR must remain in service and consistently achieving emission reduction targets between maintenance opportunities (most FCCUs, heaters, and boilers operate for years at a time, 24 hours per day and

[13] SCAQMD, 2012 AQMP, December 2012, pages 4-43.
[14] SCAQMD, BACT Guidelines, Part C: Policy and Procedures for Non-Major Polluting Facilities, 2006.

7 days per week), and composition of fuel, are a few of the factors in play with determining the costs associated with achieving the proposed levels. For example, some refinery configurations such as processes that utilize dual stacks, may require more than one SCR, and thus greater expenditures (i.e., double), to achieve the proposed level. It does not appear that such a scenario was considered by the District in developing its cost effectiveness determinations.

Accordingly, WSPA believes that the District's cost effectiveness calculations significantly understate the costs associated with achieving the proposed BARCT levels. We believe that even the Norton analysis underestimates actual costs. WSPA is currently developing additional information based on detailed engineering assessments that more accurately represent the costs associated with the proposed BARCT. We will submit this information to the record as it becomes available.

VII. Disproportionate Impacts

Under Health and Safety Code Section 39616(c)(7), the District must show that RECLAIM facilities are not being disproportionately impacted by participating in the program.[15] The draft staff report, noting the emission projections described in the 2012 AQMP, indicates that RECLAIM sources make up 37 percent of the projected NOx emissions for 2023 from stationary sources.[16] Table 2.1 of the draft staff report indicates that non-RECLAIM sources, including waste disposal and miscellaneous processes, will account for 46 tons per day of the annual average NOx emissions for the 2023 base year while RECLAIM sources (pre-shave) will account for 27 tons per day.[17]

In its proposal, the District is seeking substantial reductions from RECLAIM sources, the
1-11 majority of which come from the nine refineries in the Basin. Nonetheless, there is nothing in
the draft staff report or other proposal document that indicates what reductions will be required for non-RECLAIM facilities. In fact, there is no evidence presented that would lead the Board to make a finding that RECLAIM facilities are not taking the brunt of the load when it comes to requiring emission reductions. The District has failed to provide "appropriate information" to "substantiate" a finding of no disproportionate impact.

Indeed, for the Board to make such a finding, there must be evidence indicating that non-RECLAIM facilities are, on an aggregate basis, required to reduce their NOx emissions at the levels required by their RECLAIM counterparts (at least proportionately). Non-RECLAIM facilities represent the majority of the stationary NOx emissions, yet SCAQMD appears to be seeking *no* reductions from such sources. Barring appropriate information showing that non-RECLAIM sources are required to reduce emissions equivalent to what is proposed by these amendments, the Board cannot make the required findings and as a result, the proposed amendments violate the District's statutory mandate.

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[15] Health & Saf. Code § 39616(c)(7).

[16] SCAQMD, *Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM* (Draft NOx RECLAIM Staff Report), p. 14. (July 21, 2015)

[17] *Id.*

VIII. Energy Efficiency Projects

1-12 Staff suggests that there are NOx emission co-benefits available from Refinery Sector sources due to energy efficiency projects that are in addition to the projected emission reductions under this rule. This is essentially an erroneous assumption due to the fact that the AQMD is relying on information that was submitted under the California AB32 Energy Efficiency and Co-Benefits regulation and most of the projects that were presented by Refinery Sector facilities in those 2011 vintage reports were already completed. As such, those emissions benefits were already reflected in the 2011 baseline year emissions presented in the PDSR. AQMD Staff acknowledges as much in PDSR Table 3.2. As such, these co-benefit reductions should not be presented or characterized as a potential additional benefit.

IX. Socioeconomic Impacts

1-13 Under Health and Safety Code Section 40728.5, the District is required to perform an analysis of the socioeconomic impacts of the proposed regulation. This assessment is important because it lays out the range of probable economic impacts to the regulated industries as well as the impact on the economy of the region as a whole. Unfortunately, the socioeconomic impacts analysis is not available at this time. WSPA believes that reviewing the analysis is important to its ability to meaningfully comment on these proposed regulatory changes. Accordingly, WSPA may change or supplement its comments on review of the analysis when it is released.

Thank you for considering the comments addressed in this letter. We look forward to continuing to work with you and your Staff on this important rulemaking. WSPA reserves the right to file additional comments or other materials as this rulemaking progresses.

Sincerely,

Suzanne E. Bernicle

cc: Dr. Barry Wallerstein
Joe Casmassi

ATTACHMENT 1

ADDITIONAL COMMENTS ON PRELIMINARY DRAFT STAFF REPORT (PDSR) FOR NO_X RECLAIM AMENDMENTS

	Page/Section	WSPA Comment
1-14	Page 2, Current Emissions and RTC Holdings.	AQMD should use 2012 compliance year emissions as the baseline year for "current emissions" for all industrial sectors. WSPA understands the rationale presented by AQMD for use of 2012 data to characterize baseline Power Sector emissions. However, non-Power RECLAIM facilities were also exhibiting lower output levels in 2011 due to the recession that started in 2007. This is shown in attached Figure 1. Looking at certain key industrial sectors yields a similar conclusion. On a sectoral level, publicly reported economic data (see Figure 2A and Figure 2B) shows that economic output and emissions for the cement and textile manufacturing sectors in AQMD were also still recovering from recessionary low points in 2011. For these reasons, WSPA recommends that AQMD revise the Staff Report to use 2012 compliance year emissions as the baseline emissions year for all industrial sectors.
1-15	Page 3: Table EX-1, Summary of Proposed BARCT (May 2015).	Table EX-1 presents data for the Refinery Sector which fails to reflect changes necessitated by the findings of the third-party expert hired to confirm the AQMD Staff's Refinery Sector technical analysis for this rulemaking. The Staff's BARCT analysis for the Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[1] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. We also note that NEC has raised a significant number of technical issues with the conclusions presented in the PSDR for the Refinery Sector categories.[2] WSPA strongly suggests that these technical issues be resolved before further presentation of emissions reductions attributable to the proposed BARCT analysis.
1-16	Page 3. Last paragraph, 3rd sentence. Resolution of Uncertainties	WSPA recommends this section be re-written after the requested and required changes to the Staff's BARCT analysis have been completed. The subject paragraph suggests that Staff has "accounted for uncertainties that arose in the BARCT analysis…." We disagree. There continues to be a significant number of unresolved issues which result in uncertainty in the Staff analysis presented in the PDSR. This includes, but is not limited to the Staff's decision to selectively ignore the findings of the agreed upon third-party expert for the Refinery Sector.

[1] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

[2] James Norton, NEC, letter to Dr. Philip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

1-17	Page 3. Last paragraph, 3rd sentence. Proposed Adjustment Account	The proposed "Adjustment Account" should be accessible by all RECLAIM facilities subjected to the Rule 2005 NSR RTC holding requirement. Furthermore, AQMD Staff should provide a technical rationale to support the quantity of RTCs set aside to fund any such adjustment account. The PDSR suggests the RTC demand caused by Rule 2005 RTC holding requirements are addressed by the proposed creation of an RTC Adjustment Account for power plants. However, the RTC holding requirements imposed under Rule 2005 are also applicable to many non-Power Sector facilities under RECLAIM New Source Review. The Staff's current proposal does nothing to address the RTC demand associated with these non-Power Sector facilities. This should be resolved.
	Page 3. Last paragraph, 3rd sentence. Proposed Adjustment Account	AQMD Staff should provide a regulatory discussion detailing how this proposed Adjustment Account would be managed, and how RTCs in the account would be treated with respect the to the State Implementation Plan (SIP).
1-18	Page 3. Last paragraph, 5th sentence. Compliance Margin	WSPA recommends this section be re-written to eliminate potential misstatements concerning the level of "unused RTCs" that might be available under the Staff's proposed shave. The Staff's "Remaining Emissions" approach as presented in the PDSR limits the overall "Compliance Margin" for RECLAIM facilities to 10% of projected 2023 emissions (i.e., not 23%). The Staff's Remaining Emissions estimate excludes some RECLAIM market sectors (i.e., cement) which had reduced emissions in 2011 due to the major recession from which certain sectors were still recovering. Staff has made an adjustment to account for that omission, but this paragraph then suggests that such adjustment is part of the overall market's Compliance Margin. That is incorrect.
1-19	Page 4: 1st full paragraph. Application of Shave	The proposed NOx RECLAIM shave should be applied in an equally distributed, "Across the Board" manner consistent with RECLAIM founding principles and the precedent set under the 2005 NOx RECLAIM shave. RECLAIM is a market-based program which was designed to use "the power of the marketplace"[3] to reduce air emissions from stationary sources. This approach was expressly intended not to impose "command-and-control" requirements on specific facilities or specific equipment therein. Rather, RECLAIM was intended to provide Southern California businesses with greater flexibility and a financial incentive to reduce air pollution at least equal to what traditional command-and-control rules would have required. This program has been very successful in reducing NOx emissions with RECLAIM facilities having reduced their overall actual emissions well in excess of the program's current target under Regulation XX.

3 SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim.

		The District has previously considered and rejected targeted shaves as noted in the excerpts below: • Oct 1993, RECLAIM Program Summary: "Throughout the development of RECLAIM, the District evaluated several design options that would have treated some industries differently than others……After evaluating advantages and disadvantages, the District adopted a program that treats all sources consistently for equity and fairness." • 2005 Staff Report, Appendix E: "The Staff proposal is taking the "across-the-board" reduction of NOx RTC holdings approach by looking at the total reductions possible based on BARCT determinations and reducing allocations for all RTC holders by the same percentage…This approach, from a market design standpoint and based on the overall conceptual design of the RECLAIM program to achieve programmatic BARCT, is the most equitable…" The Staff proposal presented in the PDSR is inconsistent with the founding principles of the RECLAIM program that stressed the importance of a market-based program, as well as the precedent established by the SCAQMD in previous NOx regulatory reductions in 1999 and 2005. An equally distributed "across-the board" treatment of all sources, as originally designed and implemented since the program's inception in 1994, is critical to the continued success of the RECLAIM program.
1-20	Page 4: 1st full paragraph, 3rd sentence. Small Facilities	This sentence states "The remaining 210 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was no new BARCT for the types of equipment and operation at these facilities." This statement is factually incorrect and should be corrected. AQMD Staff opted not to review BARCT for these facilities under this RECLAIM rulemaking. Additionally, AQMD and other California air districts have previously made BARCT determinations that would apply to the equipment and operations at those smaller emitting facilities (e.g., boilers, heaters, etc.) were they not under RECLAIM.[4]
1-21	Page 4: 2nd and 3rd full paragraphs. Implementation Schedule	The proposed Implementation Schedule should be revised to shave not more than 2 tons per day (tpd) from the program in the first year. This is consistent with Governing Board's direction under Control Measure CMB-01 Phase 1. Additionally, the overall schedule should be longer than the proposed seven (7) years to ensure RECLAIM facilities have sufficient time to comply. 2012 Air Quality Management Plan (AQMP) Control Measure CMB-01) Phase 1 was approved by the Governing Board on the basis that 2 tpd would be removed from RECLAIM in the event of the $PM_{2.5}$ contingency measure being triggered.[5] The proposed schedule should be consistent with that 2 tpd State Implementation Plan (SIP) commitment; anything

4 See SCAQMD Regulation XI for examples.
5 SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.

		larger may not allow sufficient time for industry to implement emission control projects necessitated by the rulemaking. Also, the proposed schedule for full implementation by 2022 may be insufficient to achieve the proposed level of NOx emission reductions from RECLAIM facilities. Refinery Sector sources may need 8 years or more to fully engineer, permit, construct and operationalize all the projects needed to comply with the proposed rulemaking.[6]
1-22	Page 6: Table EX-2, Summary of Public Process.	To provide ample opportunity for stakeholder review and comment, AQMD Staff should revise this schedule to provide the public with a realistic schedule for this rulemaking that includes the CEQA Program Environmental Assessment (PEA) and the Socioeconomic Analysis.
1-23	Page 19: Co-Benefits of Energy Efficiency Projects.	This section should be completely removed from the PDSR or significantly revised to correct factual mischaracterizations. The information submitted by refineries to the California Air Resources Board in 2011 under the AB32 Energy Efficiency and Co-Benefits regulation reflected projects that mostly had been completed by 2011. Thus, those co-benefits were already reflected in the 2011 baseline year emissions presented in the PDSR and cannot be characterized as additional or creditable. Staff have acknowledged as much in PDSR Table 3.2.
1-24	Page 29 CEQA Alternatives	The size of the shave approved in the 2012 AQMP should be included in the list of CEQA alternatives.
1-25	Chapter 4: Costs and Cost Effectiveness. Cost Thresholds	The cost effectiveness threshold for this rulemaking should not be greater than $22,500 (i.e., the cost effectiveness threshold used in the 2012 AQMP) and the BARCT analysis presented in the PDSR should be revised accordingly. The $50,000 cost effectiveness threshold proposed by AQMD Staff is greater than the AQMD's DCF cost effectiveness threshold for Command-and-Control sources in South Coast. Under the 2012 AQMP, the approved cost threshold for NOx control measures was $22,500 per ton. As an additional data point, AQMD's current Best Available Control Technology (BACT) guidance document presents a DCF cost effectiveness threshold of only $19,100 per ton. Health & Safety Code (H&SC) §39616(c) requires that market-based program costs will be "equivalent or less compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment" and also requires "the program will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment."[7] The AQMD Staff analysis presented in the PDSR has not demonstrated that these obligations are satisfied.
	Chapter 4: Costs and Cost Effectiveness.	A 10-year "Useful Life" assumption is more appropriate given actual rulemaking timetables; the BARCT analysis presented in the PDSR should be accordingly revised to use a 10-year Useful Life assumption.

[6] Stillwater Associates LLC, RECLAIM Analysis for WSPA, July 2015.
[7] Health & Safety Code §39616(c)(1) and (7).

1-26	Useful Life Assumption	The AQMD Staff's proposed 25-year Useful Life is inappropriate because AQMD rulemaking occurs on a far more frequent recurrence. The last major NOx RECLAIM rulemaking was only 10-years ago. Use of a 25-year assumption makes the rule costs appear lower than actual by diluting the significant capital costs of required projects over a much longer time table than is likely to occur. The AQMD Staff analysis should be revised to reflect the 10-year Useful Life assumption which is more consistent with recent AQMD rulemaking schedules and is also consistent with the Useful Life assumption typically used by CARB and other major Air Districts.
1-27	Chapter 4: Costs and Cost Effectiveness. DCF Method	The BARCT analysis presented in the PDSR should be revised to utilize the Levelized Cash Flow (LCF) methodology used by CARB and other major air districts. Use of the DCF method, in combination with the proposed interest rate and Useful Life assumptions serves to distort the estimated costs for this AQMD rule by making them appear less expensive than they would be using the Levelized Cash Flow (LCF) method employed by CARB and other major Air Districts. The same threshold should be used for both DCF and LCF.
1-28	Chapter 5: RTC Reductions, Remaining Emissions Remaining Emissions Method	The AQMD Staff's "Remaining Emissions" method conflicts with Control Measure CMB-1 Phase 1 as approved under the 2012 AQMP and should be replaced with the Incremental BARCT method proposed by the Industry RECLAIM Coalition. The Remaining Emissions method presented in the PDSR conflicts with Control Measure CMB-1 Phase 1 because it would remove nearly all Unused RTCs (i.e., "surplus") from RECLAIM. CMB-01 Phase 1 explicitly considered and rejected such a reduction; instead arguing that a 2 tpd of reduction for Unused RTCs was more appropriate due to concerns that baseline RECLAIM emissions might reflect the economic downturn.[8] As noted above, many Southern California industry sectors covered by RECLAIM were in fact still under a recessionary hangover in 2011 so such concerns were valid. Furthermore, the "Incremental BARCT" method is more consistent with Control Measure CMB-1 Phase 2 approved under the 2012 AQMP[9] because the method would only remove RTCs in an amount attributable to technology advancement (i.e., BARCT). AQMD Staff's own analysis demonstrates that less than 9 tpd of proposed RTC reductions are attributable to the 2015 BARCT analysis. Yet the Staff proposal proposes to shave 14 tpd. Removing RTCs beyond what is supported by technology advancement may subject facilities in the RECLAIM program to disproportionate impacts, measured on an aggregate basis, compared to other permitted stationary sources in the District's plan for attainment. It may also subject

[8] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.

[9] SCAQMD, 2012 AQMP. Page 4-26 states: "This phase of control is to implement periodic BARCT evaluation as required under the state law." Appendix A, page IV-A-60 presents more detailed discussion for the measure.

	RECLAIM facilities to greater costs compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment. Either of these outcomes would conflict with H&SC 39616(c). AQMD has not demonstrated that the Staff proposal successfully meets these obligations. Further, under Section 40727, the Legislature has established that regulations must meet the requirements of necessity, authority, clarity, consistency, non-duplication, and reference. The necessity requirement ensures in part that unnecessary costs are not imposed on the economy of California. Accordingly, the District needs to establish that the shave is no more stringent than what is "necessary." Necessity "means that a need exists for the regulation, or for its amendment or repeal, as demonstrated by the record of the rulemaking authority."[10] Through the 2012 AQMP, SCAQMD has described that a need exists for a reduction in NOx emissions. The ceiling of that need was five tons per day. The magnitude of the current shave proposal goes above and beyond what is necessary to meet the requirements of the AQMP or any other statutory or regulatory obligation that SCAQMD faces

1-29	Chapter 5: RTC Reductions, Remaining Emissions Compliance Margin	The proposed Compliance Margin of 10% appears inadequate to meet the market's historical need for Unused RTCs and should be revised to the 20-30% range. The RECLAIM market has exhibited "Unused RTCs" since program inception. This may be for several reasons including facility compliance margins which range in size depending on facility size and/or risk tolerance, RTC holding requirements imposed under Rule 2005, or market trading to name few. These Unused RTCs have historically averaged in the 15-30% range (5 to 9 tpd) with the sole exception being the market crisis during the 2000 compliance year.[11] The AQMD Staff's proposal (with only 10% compliance margin) may be inadequate for satisfying this market requirement. Excessive shaving of Unused RTCs could result in a market which is unable to accommodate the economic activity levels projected in the Staff's analysis. Furthermore, removal of all Unused RTCs would directly conflict with Control Measure CMB-01 Phase 1 as authorized by the Governing Board.
1-30	Chapter 5: RTC Reductions, Remaining Emissions Table 5.1 – Remaining Emissions for Refinery Sector (May 2015)	The BARCT analysis for the Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review, and Table 5.1 should be accordingly revised. As noted in the PDSR, the Staff analysis fails to account for the technical recommendations from NEC, the third-party Refinery Sector expert hired by the AQMD. NEC's findings have material impacts on the resulting BARCT determinations for certain Refinery Sector categories. Once corrected, the projected "2023 Remaining Emissions at 2015 BARCT" for the Refinery Sector will increase, and the "2023 Emission Reductions Beyond 2000/2005 BARCT" will decrease. These technical corrections are critical to a fair application of the proposed shave.

10 Health & Saf. Code § 40727.
11 SCAQMD, Annual RECLAIM Audit Report for 2013 Compliance Year, 6 March 2015. See Table 3-2.

	Appendix A - Refinery Fluid Catalytic Cracking Units (FCCUs) Page 53. Incremental Costs and Cost Effectiveness Cost Effectiveness Calculations	The cost effectiveness analysis presented for FCCUs in Appendix A does not consider the 2000/2005 BARCT emissions or cost baselines. This conflicts with the methodology outlined in Chapter 4. The Staff BARCT analysis should be accordingly revised based on the incremental cost effectiveness approach outlined in Chapter 4. Staff proposes that the cost effectiveness of 2015 BARCT is to be calculated based on the incremental cost of progressing from 2000/2005 BARCT to the proposed 2015 BARCT level, divided by the incremental emissions benefit related to the progression from 2000/2005 BARCT to the proposed 2015 BARCT level (i.e., "2023 Emission Reductions Beyond 2000/2005 BARCT"). For some reason, it was not applied in this manner for the FCCUs. We request that this oversight be corrected.
1-31	Appendix A - Refinery Fluid Catalytic Cracking Units (FCCUs) Page 53. Incremental Costs and Cost Effectiveness Consideration of Third-Party Expert's Recommendations on Cost	The Staff's BARCT analysis for the Refinery FCCUs category should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[12] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings, without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. We also note that NEC has raised a significant number of technical issues with the conclusions presented in the PSDR for the Refinery FCCUs which have reportedly been discussed with Staff and were reiterated in NEC's letter dated 10 August 2015.[13] Norton's comments are attached hereto and incorporated herein by reference. These technical issues are significant and should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis.
1-32	Appendix B – Refinery Boilers and Process Heaters Page 60, Achieved-In-Practice NOx Levels for Boilers and Heaters Proposed BARCT	WSPA requests further technical demonstration to support the proposed BARCT level for refinery heaters and boilers; the proposed BARCT level does not appear to represent an achievable level of performance for most refinery heaters/boilers operating on refinery fuel gas. According to the AQMD's figures, fewer than 10% of the heater/boiler units already equipped with SCR technology are able to achieve the proposed BARCT level. This does not suggest the performance level can be broadly achieved with add-on emissions controls. If this level of performance effectively demands basic equipment replacement, the AQMD's BARCT analysis should identify and quantify costs for that demand. WSPA also requests clarification on the number of refinery heaters and boilers reported to that have "very low emissions levels." AQMD Staff have provided conflicting counts to stakeholders, and those counts conflict

[12] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

[13] James Norton, NEC, letter to Dr. Philip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

		with information provided to WSPA directly by WSPA member refineries.[14] The PDSR reports fourteen refinery heaters in the AQMD as using refinery fuel gas and achieving NOx concentrations "between 1.6 and 3.5 ppmv" (corrected to 3% O2) using Selective Catalytic Reduction (SCR) technology. AQMD Staff also report that two boilers have achieved NOx emissions between 2 and 5 ppmv using LoTOx scrubbers and natural gas. We understand that AQMD's analysis is based on data collected from Southern California refineries under a 2013 survey.[15] AQMD had previously reported to the RECLAIM Working Group that, based on that same survey, only nine refinery heaters/boilers were achieving below 5 ppmv. WSPA requests clarification on how this count of units with "very low emissions levels" could have changed. Lastly, AQMD should not categorize units between performing "between 1.6 and 3.5 ppmv" as a single group consistent with the proposed BARCT. 3.5 ppmv does not equal 2 ppmv, and some units which achieve 3.5 ppmv may be unable to meet 2 ppmv even with add-on controls. We would suggest this group supports a BARCT determination of 3.5 ppmv; not 2 ppmv.
1-33	Appendix B – Refinery Boilers and Process Heaters Page 60, Achieved-In-Practice NOx Levels for Boilers and Heaters Cost Basis for BARCT and Consideration of Third-Party Expert's Recommendations on Cost	The Staff's BARCT analysis for the Refinery heaters and boilers should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review, and any subsequent comments from NEC.[16] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. The AQMD Staff's analysis suggests that the proposed BARCT level of 2 ppmv can be achieved with less equipment (e.g., 1 layer of catalyst) and less cost than suggested by the third-party Refinery expect; a firm that engineers such equipment as its primary business. Counter to the AQMD Staff's assertion that NEC was simply wrong on its design basis is the fact (reported by AQMD)[17] that fewer than 10% of the existing Refinery heaters/boilers with SCR technology are able to meet 2 ppmv. This result includes both new and retrofit installations and suggests that the proposed 2 ppmv NOx performance level may not be as easily achieved as suggested by Staff. Given the material impact of these technical issues on the BARCT analysis, they should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis. Specifically, we request that the BARCT analysis presented in Appendix B be revised to consider the cost estimates presented by NEC.
	Appendix B – Refinery	The BARCT cost effectiveness analysis presented in this table suggests

[14] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, Mar 2015.
[15] SCAQMD, Preliminary Draft Staff Report (PDSR) for Proposed Amendments to NOx RECLAIM, 21 July 2015.
[16] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[17] SCAQMD, NOX RECLAIM Working Group Meeting, 19 September 2013.

1-34	Boilers and Process Heaters Table B.11 - Details of Cost Estimates for Boilers and Heaters (March 2015)	AQMD Staff have selectively applied the methodology outlined in Chapter 4. This is specifically a problem for select heaters which are reportedly already meeting proposed BARCT. In these instances, Staff has claimed emissions reductions relative to the 2000/2005 BARCT level without assigning any programmatic costs for those reductions. This is inconsistent with the programmatic approach outlined in Chapter 4, under which cost effectiveness of 2015 BARCT is to be calculated based on the incremental cost of progressing from a 2000/2005 BARCT level to the proposed 2015 BARCT level, divided by the incremental emissions benefit related to the progression from 2000/2005 BARCT to the proposed 2015 BARCT level (i.e., "2023 Emission Reductions Beyond 2000/2005 BARCT"). WSPA does not believe it appropriate for Staff to selectively "pick and choose" when use the prescribed programmatic approach. The Staff BARCT analysis should be revised accordingly to be fully consistent with the incremental cost effectiveness approach outlined in Chapter 4.
1-35	Appendix D - Coke Calciner Staff's Recommendation	WSPA appreciates that AQMD Staff accepted NEC's recommended BARCT level of 10 ppmv and has incorporated it into the BARCT analysis for this source category.
1-36	Appendix E - Sulfur Recovery Units/Tail Gas Incinerators Page 110. Costs and Cost Effectiveness Design Basis for BARCT and Consideration of Third-Party Expert's Recommendations	The Staff's BARCT analysis for the Refinery Sulfur Recovery Units/Tail Gas Incinerators (SRU/TG Incinerators) category should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[18] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. As with other categories, the AQMD Staff's analysis suggests that the proposed BARCT level of 2 ppmv can be achieved for SRU/TG Incinerators with less equipment (e.g., fewer layers of catalyst) and less cost than suggested by the third-party Refinery expert; a firm that engineers such equipment as its primary business. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. Given the impact of these technical issues on the projected emissions and costs for this category, these issues should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis. Specifically, we request that the BARCT analysis presented in Appendix E be revised to consider the cost estimates presented by NEC. Tables E.1 and E.2 should include NOx concentration levels.
1-37	Appendix K – Co-Benefits of Energy Efficiency Projects	This appendix should be completely removed from the PDSR or significantly revised to correct factual mischaracterizations.

[18] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

	The information submitted by refineries to the California Air Resources Board in 2011 under the AB32 Energy Efficiency and Co-Benefits Regulation reflected projects that had mostly been completed by 2011. Thus, those co-benefits were already reflected in the 2011 baseline year emissions presented in the PDSR and cannot be characterized as additional or creditable. Staff have acknowledged as much in Table K.1 and also PDSR Table 3.2.

1-38

Part III – RTC Reduction Approaches Appendix U – Staff's Proposal and CEQA Alternatives	The proposed NOx RECLAIM shave should be applied in an equally distributed, "Across the Board" manner consistent with RECLAIM founding principles and the precedent set under the 2005 NOx RECLAIM shave. RECLAIM is a market-based program which was designed to use "the power of the marketplace"[19] to reduce air emissions from stationary sources. This approach was expressly intended not to impose "command-and-control" requirements on specific facilities or specific equipment therein. Rather, RECLAIM was intended to provide Southern California businesses with greater flexibility and a financial incentive to reduce air pollution at least equal to what traditional command-and-control rules would have required. This program has been very successful in reducing NOx emissions with RECLAIM facilities having reduced their overall actual emissions well in excess of the program's current target under Regulation XX. The District has previously considered and rejected targeted shaves as noted in the excerpts below: • Oct 1993, RECLAIM Program Summary: "Throughout the development of RECLAIM, the District evaluated several design options that would have treated some industries differently than others……After evaluating advantages and disadvantages, the District adopted a program that treats all sources consistently for equity and fairness." • 2005 Staff Report, Appendix E: "The Staff proposal is taking the "across-the-board" reduction of NOx RTC holdings approach by looking at the total reductions possible based on BARCT determinations and reducing allocations for all RTC holders by the same percentage…This approach, from a market design standpoint and based on the overall conceptual design of the RECLAIM program to achieve programmatic BARCT, is the most equitable…" The Staff proposal presented in the PDSR is inconsistent with the founding principles of the RECLAIM program that stressed the importance of a market-based program, as well as the precedent established by the SCAQMD in previous NOx regulatory reductions in 1999 and 2005. An equally distributed "across-the board" treatment of all sources, as originally designed and implemented since the program's inception in

[19] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim.

	1994, is critical to the continued success of the RECLAIM program.

SUPPORTING FIGURES

Figure 1. U.S. Excluding California, California Excluding SCAQMD, and SCAQMD Output Index, All Regulated Industries Combined, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)

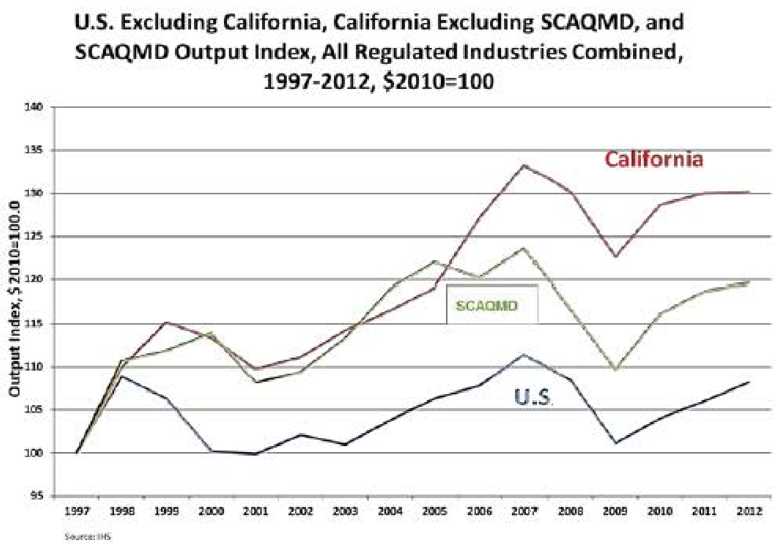


Figure 2A. South Coast AQMD Region Cement Output and Emissions, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)

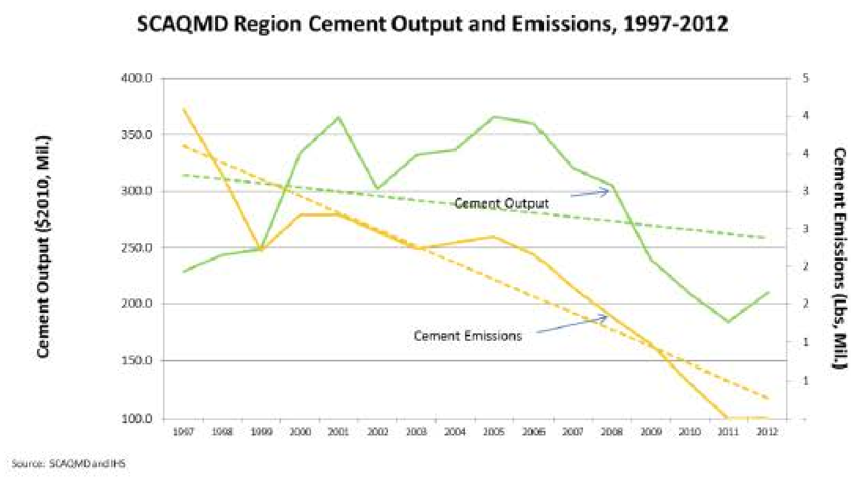
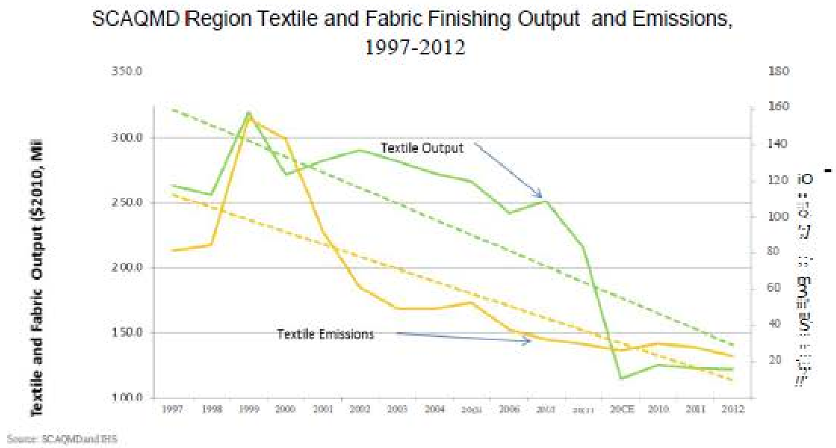


Figure 2B. South Coast AQMD Region Textile and Fabric Finishing Output and Emissions, 1997-2012
(Source: Kavet, Rockier & Associates based on data from his IHS County-Level Economic Database, 2015)



Responses to Letter #1

Response 1-1 Previous WSPA Comment Letters

Please see staff's responses to previous WSPA and the Industry Coalition's letter and comments attached to the Draft Socioeconomic Staff Report.

Response 1-2 Shave Methodology and Arbitrary Removal of Unused RTCs

Staff disagrees with the commenter's assessment in several areas.

Intent of Control Measure CMB-01 and RTC Reductions

It is important to understand that the Basin is currently classified as a "severe" non-attainment area for PM2.5 and "extreme" non-attainment for ozone. Based on recent data, the Basin did not meet the PM2.5 ambient air quality standards by the original attainment date of 2014 or the revised attainment date of 2015. Thus, staff is obligated to find all technological feasible and cost-effective control technologies to help the Basin achieve maximum emission reductions and attain the PM2.5 and ozone ambient air quality standards as expeditiously as possible. Control Measure CMB-01 is a control measure in the 2012 AQMP that called for a total NOx reduction of 3-5 tpd in 2 phases: 2-3 tpd in Phase I with implementation date in 2014 (already overdue) and 1-2 tpd in Phase II with implementation date in 2020.[7, 8] Staff committed to submit 3 tpd, the lower end of the range, to satisfy the SIP commitment. The intent of the Control Measure CBM-01 was not to limit the reduction to 3-5 tpd: [9]

> *"It should be noted that since there are substantial NOx reductions needed by 2023, if additional reductions are feasible and cost effective, they will be evaluated during rulemaking."*

The control measure also states that the District is required to monitor advances in BARCT, and if BARCT advances, the District is required to periodically re-assess the overall facility caps, and reduce the RTC holdings to applicable equivalent command & control BARCT levels.

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[7] The implementation dates are shown in Tables 4-2 and 4-4 of the 2012 AQMP

[8] The 2 tpd in the statement that WSPA cited "The control measure will seek further reductions of 2 tpd NOx allocations if triggered" on page 4-9 of the 2012 AQMP refers to the additional 2 tpd in Phase 2.

[9] Page IV-A-60, Appendix IVA of the 2012 AQMP

Staff has identified and evaluated all feasible and cost-effective BARCT to achieve 14 tpd RTC reduction as proposed in the PDSR. As stated in Control Measure CMB-01, the Control Measure did not limit the reduction to 3-5 tpd. There is no language in control measure CMB-01 that explicitly considered and rejected removing more than 2 tpd of unused RTCs.

Regarding the implementation schedule for the 14 tpd RTC reduction, in the 5 years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5 to 8 tpd, [10] thus staff is proposing a 4 tpd RTC reduction in 2016. Additional reduction from implementation of BARCT will take 2 - 4 years for procurement, engineering, planning, and construction, therefore staff is proposing that the remaining shave of 10 tpd take place over 5 years between 2018 and 2022.

Methodology for BARCT Reductions & Removal of Unused RTCs

On contrary with the commenter's assessment, Control Measure CMB-01 from the 2012 AQMP does not prescribe how the shave should be calculated and thus it is not in conflict with the shave methodology. The proposed shave in the RECLAIM program is estimated based on remaining emissions. This proposed method is consistent with past practice in the 2005 and 2010 RECLAIM amendments.

To calculate the shave, staff first estimated the remaining emissions at BARCT levels projected to the compliance year 2023 including economic growth and 10% compliance margin. The shave was calculated as the difference between the current RTC holdings and the remaining emissions projected to 2023. Staff also reduced the shave by 0.85 tpd to account for uncertainties and provide some additional compliance margin. The total shave proposes removal of RTCs necessary to attain BARCT levels of emissions, including removing some unused surplus RTCs in the market.

Shave = Current RTC Holdings – (2023 Remaining Emissions + Uncertainty)
= RTCs attributable to difference between 2000/2005 & 2015 BARCT + Portion of Unused RTCs
= 26.5 – (11.67 + 0.85) = 8.8 + 5.2 = 14 tpd

WSPA has suggested staff remove only the RTCs directly attributable to technology advancement (8.77 tpd) but not the unused RTCs. The unused RTCs however create a dampening effect on RTC prices that allows RECLAIM facilities to purchase RTCs in lieu of implementing BARCT. For example, in 2009-2013, there were about 5 – 8 tpd surplus RTCs in the market and the average RTC prices were in a range of $1,162 – $5,491 per ton compared to the average cost-effectiveness

[10] Table 1.1 of the Preliminary Draft Staff Report

of control range $8,300 - $13,000 per ton.[11, 12] Thus, the facilities opted to purchase low cost abundant surplus RTCs to reconcile their emissions at the end of the compliance year in lieu of installing control to reduce "real" emissions. For example, the refineries did not install any SCRs in responses to the 2005 NOx RECLAIM amendment even though staff had estimated about 51 SCRs would be installed by 2011. Removing surplus RTCs is therefore critically important to ensure the effectiveness of the RECLAIM program and meet state law requirements to require the use of BARCT for existing sources.

WSPA has suggested staff estimate the shave based the projected actual emissions but not the current RTC holdings.[13] However, removing 8.77 tpd from current RTC holdings will not be enough to ensure that the RECLAIM universe emits at an emission level that represents the maximum degree of reductions achievable as required by H&SC 40406. Staff analysis has shown that the RECLAIM universe can achieve a level of 12.5 tpd remaining emissions. To reduce RTCs from the current 26.5 tpd to reach the target of 12.5 tpd requires a "shave" of 14 tpd. A smaller shave would be met by simply giving up unused RTCs, not producing any significant actual emission reductions.

Compliance Margin

RECLAIM facilities typically hold extra RTCs in their account to ensure that they will have enough RTCs to reconcile their emissions at the end of the compliance year.[14] Plant operation and emissions may fluctuate. CEMS may be offline and facilities must use missing data procedures to calculate emissions which may be higher than actual emissions. Also, facilities may underestimate their actual emissions and need to hold a stream of RTCs to account for adjustments after audit. In previous RECLAIM amendments, staff provided 10% compliance margin to help the facilities deal with these uncertainties. Staff did the same in this amendment allowing a 10% compliance margin but actual unused RTCs may be even higher. As illustrated below, this level of compliance margin will result in 23% unused RTCs above the remaining emissions. Staff believes this will adequately meet the market's need for unused RTCs.

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[11] Discrete RTC prices shown in Figure 1.2 of the PDSR: $1,162 - $5,491 per ton for 2005-2012.

[12] Cost effectiveness for individual source categories: $11,000 - $17,000 per ton for refinery boilers/heaters >110 mmbtu/hr and FCCUs, $9,000 - $10,000 per ton for industrial boilers, $4,000 - $11,000 per ton for metal melting/heat treating and miscellaneous combustion (page 3 of the Board Letter for the 2005 NOx RECLAIM Amendment, Agenda No. 25, January 7, 2005). Overall program average cost effectiveness: $8,300 - $13,000 per ton (page 8 of the Board Letter for the 2005 NOx RECLAIM Amendment, Agenda No. 25, January 7, 2005).

[13] Industrial Coalitions' Approach: Shave = Projected 2011 Emissions @ 2005 BARCT – Projected 2023 Emissions @2015 BARCT = 8.77 tpd. Staff's Approach = RTC Holdings – 2023 Remaining Emissions – Adjustment = 14 tpd

[14] Page 54 the Staff Report of the 2005 NOx RECLAIM Amendment.

Remaining RTCs after shave = 26.5 tpd – 14 tpd = 12.5 tpd
Remaining emissions = 2.71 tpd (refinery) + 7.47 tpd (non-refinery) = 10.18 tpd
Surplus RTCs = 12.5 tpd – 10.18 tpd = 2.3 tpd
% Unused RTCs = 2.3 tpd / 10.18 tpd = 23% above remaining emissions

The compliance margin is not expected to meet the RTC holding requirements imposed under Rule 2005. Instead, staff has created a Regional NSR Holding Account to help facilities in the power sector subject to Rule 2005 NSR requirements. This Account will be taken from the 14 tpd shave and not from the post-shave unused RTCs. Staff has discussed this issue with the U.S. EPA to seek their approval on the concept and receive feedback on whether or not this concept can be applied to all RECLAIM facilities.

Staff believes the compliance margin is not needed to create market liquidity. It is envisioned that the facilities would install control equipment to reduce emissions to the BARCT levels as required by state law and would create surplus RTCs to trade and keep the market liquid.

Response 1-3 Shave Application and Implementation Schedule

At the inception of the RECLAIM program in 1993, the compliance year 2000 allocations were estimated for each facility in RECLAIM based on the methodology described in Rule 2002(d), and the compliance year 2003 allocations were estimated based on the methodology described in Rule 2002(e). There was no “across-the-board” uniform percentage shave.

In the 2005 NOx RECLAIM amendment, a uniform percentage shave (22.5%) was applied “across-the-board” because the BARCT identified at that time was applicable to “across-the-board” facilities (e.g. low NOx burners for ovens, kilns, furnaces.)

The shave for the SOx RECLAIM in 2010 was not distributed “across-the-board” because 1) the BARCT identified was applicable to only 11 major facilities,[15] and 2) the non-uniform characteristics of the market made it inequitable to distribute the shave to all facilities.[16] To ensure that the 11 major facilities would install BARCT equivalent to command-and-control and to keep other facilities in the market, the 2011 SOx shave was applied only to investors and one-third of the facilities in the SOx RECLAIM universe.

It should be noted that the methods used to establish the 1993, 2005 or 2010 shaves did not establish founding principles and precedence on how the shave must be distributed. How the shave

[15] The 11 major facilities included six refineries, a coke calciner, two sulfuric acid plants, a cement plant, and a glass plant.

[16] The 11 major facilities hold 87% of RTCs and contributed more than 94% of emissions. The remaining 21 facilities hold 6% of RTCs and contributed 6% of emissions.

should be distributed in each rule amendment is affected by the BARCT identified, the distribution of RTCs in the market, and staff's analysis on how best to implement BARCT.

For the proposed rule amendment, staff identified the new BARCT applicable for 20 major facilities (9 refineries and 11 non-refineries) and recommended shaving 56 facilities that hold 90% of the NOx RTCs and contributed 86% of the emissions. Staff proposed not to shave the remaining 219 facilities that hold only 10% of the NOx RTCs to keep them in the market.

Regarding the different shave percentages for the refinery sector and the non-refinery sector, staff estimated that by implementing BARCT the refinery and non-refinery sector could reduce 6.00 tpd and 2.77 tpd, respectively. Therefore, staff proposed shaving the RTC holdings from the refinery sector at a higher rate than the non-refinery sector weighted by the emission reductions that could be achieved. Staff proposed to shave the refinery sector by 66% and the non-refinery sector by 47%. The non-uniform shave is to ensure that the facilities subject to BARCT would install BARCT. After a shave of 22.5% "across-the-board" in 2005, the refineries opted to buy unused RTCs and not install any SCRs to reduce NOx emissions even though staff had estimated it was feasible and cost-effective for the refineries to install 51 SCRs by 2011.

In this case, if the percent shave were set at the same amount "across-the-board", facilities that do not have available BARCT, or where BARCT technology does not achieve the uniform 53% reduction, would have to purchase more RTCs from the refineries that can achieve 66% reduction. This would result in a redistribution of wealth from the non-refinery sectors to refineries. While this occurs to some extent under the staff proposal, the effect would be greatly increased.

For CEQA and socioeconomic analyses, staff considered five alternative approaches to allocate the RTC reductions. All five alternatives have "across-the-board" shave. The challenge of the RECLAIM program is to find the most appropriate shave distribution to protect the environment, attain the NAAQS, satisfy state and federal CAA requirements and AQMP commitments, and at the same time, allow for economic growth, provide equity, and safeguards for the functioning of the RECLAIM program.

With respect to the implementation time, because the implementation date for 2 tpd reductions in Phase 1 was due in 2014 and there are 5-8 tpd surplus RTCs in the market, staff believes that at a minimum 2 tpd reduction or up to 4 tpd reduction should be removed from the market no later than 2016, not "back-loaded" to 2019 as the commenter suggested. As explained in Response 1-2, the removal of unused RTCs is expected to raise the RTC prices and stimulate the implementation of control equipment. It is urgent to implement the control equipment and reduce actual emissions as expeditiously as possible to meet the NAAQS for PM2.5 and ozone.

Staff has planned for a sufficient lead time of approximately 2-3 years for the procurement, planning and engineering of BARCT. Except for the retrofits of Refinery 1's gas turbines scheduled in 2018, staff currently estimated that other retrofits would occur in 2019-2022 consistent with the commenter's recommendation. Staff has estimated that Refinery 1's gas turbines would be retrofitted in 2018 because the units have turnaround scheduled annually. This estimated schedule is used in the socioeconomic analysis with an assumption that the unused RTCs will be removed from the market early.

Response 1-4 Useful Life of Control Equipment

In the cost analysis for the proposed NOx RECLAIM amendment, staff has used a 25-year useful life for SCRs, LoTOx/scrubbers, and UltraCat applications. The commenter suggested that staff should have used a 10-year life since rule amendment is likely to occur in a 10-year interval (e.g. previous NOx RECLAIM amendment in 2005) and thus a 25-year life assumption makes the rule costs appear lower that they actually are by diluting the significant capital costs of required projects over a much longer time table than is likely to occur.

Staff used a 25-year life to be consistent with the following facts: [17]

1) The actual profile of SCRs in the SCAQMD: 27% of the refinery combustion equipment in the Basin has SCRs installed more than 25 years ago, and 63% of the refinery combustion equipment has SCRs installed more than 20 years ago. These units are still in operation and thus support the assumption of a 25-year useful life in the cost analysis.

2) Other air districts' staff has used similar assumption for control equipment life in their cost analysis: a) Some SCRs for refinery heaters in the Bay Area were installed in 1984 and thus the Bay Area air district staff uses a 20-year useful life in rule development. b) The SCRs in the Santa Barbara air district were installed in 1980-1990's and are still in good operating conditions, and thus the Santa Barbara air district staff supports a 25-year useful life of control device. c) Staff found several BACT analyses for the air districts in Florida that used 20- or 25-year useful life for SCRs.

3) The EPA OAQPS Costs Guidelines use a 20-year life for control equipment such as SCRs in their cost analysis.

4) Air pollution control manufacturers that staff contacted indicated that 20- or 25-year life is a reasonable assumption for control device such as SCRs, scrubbers, or LoTOx applications.

[17] Presented at the April 29, 2015 Working Group Meeting.

The commenter is concerned that a future RECLAIM amendment may require removal of equipment installed to meet the 2015 shave, so that the actual useful life is less than 25 years. This hypothetical has not been borne out by past experience. Even though the RECLAIM amendment was revised in 2005 and staff had estimated that the refineries would have to install 51 SCRs for refinery boilers/heaters by 2011, only 4 of these boilers/heaters were retrofitted with SCRs in responses to the EPA consent degrees or order of abatement. None of the SCRs were installed in responses to the 2005 BARCT assessment. Staff 2015 BARCT analysis did not identify any control equipment that would need to be removed in order to comply with the 2015 BARCT.

Furthermore, BARCT requirements were not revised in 2005 for refinery gas turbines, refinery SRU/TGTUs, refinery boilers/heaters >40 – 110 mmbtu/hr, glass melting furnaces, cement kilns and ICEs, thus the time interval between the BARCT assessments for these units is actually 22 years counting from the inception of the RECLAIM program in 1993. Adding several years allowed for planning, engineering, permitting, construction, and procurement of control equipment, the total time interval between installations of control equipment would be about 25 years.

The commenter implied that CARB may use a 10-year life for control devices. SCRs or scrubbers for major stationary sources are more durable than catalytic filters for mobile sources. CARB may use a 10-year life in their cost analysis for mobile source rules; however staff has consistently used a longer life when applicable in the cost analysis for major stationary sources: 1) a 25-year life was used in the cost analysis for electrostatic precipitators to control particulate emissions from FCCUs in Rule 1105.1; 2) a 20-year life was used for domes for refinery storage tanks in Rule 1178; 3) a 25-year life was used for SCRs in the 2005 NOx RECLAIM amendment; 4) a 25-year life was used for scrubbers in the 2010 SOx RECLAIM amendment; and 5) a 20- to 25-year life was used in Rule 1111. For other rules and regulations such as Rule 1146.1 and Rule 1147 that addressed low NOx burners, staff may use less than 25-year life depending on the type of control equipment and stationary sources. Finally, the commenter's concern can be addressed in any future RECLAIM amendment. In the event that the Board amends the rules in the near future to render obsolete any control equipment added, staff would add those stranded costs to the cost of that future amendment or consider a longer compliance schedule to maximize the useful life of the control equipment as much as possible.

Response 1-5 BARCT Analysis

In its comment letter electronically delivered on August 21, 2015, the Western States Petroleum Association (WSPA) claimed that "[…] RECLAIM must achieve emission reductions equivalent to or greater than traditional command and control, or BARCT. Thus, a NOx shave equivalent to BARCT (which the District proposes at 8.77 tpd) would be the level for comparison with the Health and Safety Code provision stating that equivalent or greater reductions would be achieved at `equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment.' Yet, SCAQMD does not seek merely its determined BARCT equivalency level of 8.77 tpd; it seeks 14 tpd of NOx reductions and has not demonstrated that such reductions will be achieved at equivalent or lower cost than BARCT. The additional 5.21 tpd reduction goes above and beyond BARCT. […]"

1) **Removing 8.77 tpd of NOx RTCs would not result in the BARCT-equivalent level of actual NOx emission reductions:** BARCT requires *actual* emission reductions. The 2015 BARCT analysis demonstrated that there would be an actual NOx emission reduction of 8.77 tpd from the 2011-2012 activity levels at 2015 BARCT compared to the same activity levels at 2005 BARCT. This represents 8.77 tpd reductions in actual emissions. If the overall NOx RTC holdings had closely matched the total amount of actual NOx emissions from the NOx universe, the removal of 8.77 tpd of NOx RTCs would likely induce an equivalent amount of actual NOx emission reductions. However, over the past five years, actual NOx emissions from RECLAIM facilities fell below the overall NOx RTC holdings by 21-30%, resulting in approximately 5.45-8.41 tpd of unused NOx RTCs (unused for compliance purposes). Therefore, the removal of 8.77 tpd of NOx RTCs would first eliminate some, if not all, of these unused NOx RTCs from the market and only thereafter result in actual emissions reductions. Therefore, total emission reductions would be less than the BARCT-equivalent level of actual NOx emission reductions. The problem of excess unused RTCs is illustrated by the fact that the 2005 NOx shave did not achieve 2005 BARCT levels for the RECLAIM universe. The 7.7 tpd of NOx shave adopted in the 2005 RECLAIM amendments was phased in over the period of 2007-2011; however, only about 4 tpd of actual NOx emission reductions occurred between 2006 (the year before the 2005 shave began) and 2012 (the year after the 2005 shave was fully phased in). Almost two-thirds of the actual emission reductions resulted from facility shutdowns, not installation of controls or other changes at RECLAIM facilities. Therefore, as long as there are persistently unused RTCs available in the market, the RTC shave would need to be larger than the tons of emission reductions calculated for the BARCT analysis to induce an equivalent level of actual emission reductions. The proposed phased-in shave of 14 tpd is anticipated to be able to induce sufficient emission reductions by 2023 so that the expected total NOx emissions from the RECLAIM universe in 2023 would be consistent with the projected NOx emissions in 2023 at the 2015 BARCT levels. (Please see the Staff Report for the shave methodology.)

   In summary, staff disagrees with WSPA's comment that the proposed phased-in shave of 14 tpd would go "above and beyond BARCT."

2) **Installation of pollution control equipment is just one of the compliance options and the estimated control installation costs may not be fully incurred to achieve the BARCT-equivalent level of actual NOx emission reductions:** Unlike the traditional command-and-control regulations that typically requires the installation of pollution control equipment on all

emission sources, a RECLAIM facility has the flexibility of using RTCs to offset its facility-wide emissions and is expected to do so whenever it is the least costly option. Since the 1970s, economic research has demonstrated, both theoretically and empirically, that the compliance flexibility offered by such cap-and-trade programs generates cost-savings (e.g., Tietenberg 1990; Chan et al. 2012).[18]

The major source of the cost-savings under any cap-and-trade program is the differential in each market participant's ability to cost effectively reduce emissions. For a facility that can more cost-effectively reduce emissions, it benefits from the sale of surplus emission credits to offset pollution control installation costs; whereas for a facility that finds actual emission reductions too costly, it buys emission credits to account for the emission reductions that can be more cost-effectively achieved elsewhere. Therefore, emission credit prices in a well-functioning market must lie in between the upper and lower bounds of cost per ton of emission reductions among all market participants. If there is a large oversupply of emission credits and the market price ends up too low, there will be little incentive for facilities to implement any actual emission reductions.

A RECLAIM facility is expected to retrofit an emission source only when it meets both of the following conditions: first, it does not hold sufficient RTCs to offset facility-wide emissions at the end of the compliance period; second, the cost of control installation per ton of emission reduction is lower than the expected average RTC price over the life of the control equipment. Even if a facility finds it more cost-effective to install pollution control equipment, it still would not incur the full cost of control installation if control installation results in surplus RTCs that the facility eventually sells to offset the control installation cost. In comparison, command-and-control regulations would require, under all circumstances, that this same facility install the control equipment and incur the full cost of control installation. As a result, total costs to install controls under RECLAIM will always be equal to or less than under command and control. Under command and control, each facility must install the required controls, whereas under RECLAIM, the highest cost option is where each facility installs BARCT controls, because the total actual costs may be lower if a facility identifies any other more cost-effective alternative to remain in compliance.

3) **California Health & Safety Code §39616 applies, if at all, to the entire RECLAIM program since adoption, and not to a single shave:** The WSPA comment letter interpreted

[18] Tietenberg, Thomas H. 1990. "Economic Instruments for Environmental Regulation." *Oxford Review of Economic Policy*. 6 (1): 17-33. Chan, Gabriel, Robert Stavins, Robert Stowe, and Richard Sweeney. 2012. "The SO2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation." Cambridge, Mass.: Harvard Environmental Economics Program.

that H&SC §39616 applies to the adoption of RECLAIM and also separately to each of the subsequent amendments. Staff disagrees with this interpretation. H&SC §39616 (c) specifies that: "In adopting rules and regulations to implement a market-based incentive program, a district board shall, at the time that the rules and regulations are adopted, make express findings." One of those findings pursuant to H&SC §39616 (c)(1) is that emission reduction benefits and the costs of the program shall be compared with those of "current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment." H&SC §39616 (c) does not refer to "amendments". Nevertheless, assuming that the finding needed to continue to be made upon amendment of the rules, it makes sense to make that finding with respect to the entirety of the RECLAIM program since its adoption because the statute repeatedly refers to "the program" in specifying findings that need to be made. Thus, the structure of H&SC §39616 is directed to the program as a whole, which includes the entirety of the program since its adoption. With the exception of the 2000-2001 period when the California energy crisis took place, the historical discrete NOx RTC prices ($5,500 or lower per ton) have consistently been at the lower end of or below the cost-effectiveness range of pollution controls. As a result, many RECLAIM facilities have accrued substantial cost-savings over the years by being able to delay or forego the installation of pollution control equipment that would have been required at different points in time by command-and-control regulations. And even if the H&SC §39616 (c)(1) finding needs to be made for this proposed shave alone, the proposed shave is expected to only reduce the future stream of this cost-savings. Even so, a reduced cost-saving is still a cost-savings compared to command-and-control regulations. Thus, this amendment will clearly not cost more than the projected cost of command and control.

Staff acknowledges that, for a portion of the smaller emitters that have no cost-effective controls identified so far, they may have been affected by past RTC price spikes and could potentially be impacted by any future price fluctuations, either due to their RTC holdings or their limited financial capacity to hedge against price volatilities. However, their potential losses would be at the same time economic gains for the RTC sellers; therefore, the resulting net cost, if any, is expected to be zero or negligible to the entire RECLAIM program, particularly compared with the program's cost savings. While individual facilities may experience different costs and savings, H&SC §39616 applies to the RECLAIM universe as a whole.

It is misleading to separate the proposed NOx RTC shave into 8.77 tpd and 5.21 tpd and to argue that the 5.21 tpd shave of excess unused RTCs goes beyond BARCT, because BARCT is defined as the maximum degree of emissions reductions achievable (H&SC § 40406), and a shave of 14 tpd from current RTC levels of 26.51 tpd is necessary to attain the 12.51 tpd (26.51 tpd – 14 tpd = 12.51 tpd) of remaining NOx emissions in 2023, which staff analysis shows can be achieved with 2015 BARCT, after making allowances for growth, a compliance margin, and uncertainties that arose in the BARCT analysis. As a result, the 14 tpd shave does not go beyond BARCT. For the same reason, it is a distorted assertion that the estimated full control installation cost of $0.62-1.09 billion should be attributed to 8.77 tpd of NOx RTC shave only, with additional costs allegedly attributable to shaving the 5.21 tons of excess unused RTCs. This cost was estimated for *actual* NOx emission reductions of 8.77 tpd under command-and-control regulations, and it serves as the most conservative (i.e., maximum) estimate of the overall compliance cost for the proposed NOx shave of 14 tpd that will be needed to achieve the BARCT-equivalent level of NOx emission reductions. As noted above, costs to RTC buyers are offset by gains to RTC sellers so that this factor does not increase costs to the RECLAIM universe. The claim that costs should include the "value" of shaved RTCs is addressed below.

In the 2005 RECLAIM amendments, some stakeholders commented that the shaved RTCs would result in real, significant financial cost to companies and should be recognized as a cost. However, staff disagreed at the time RECLAIM was first adopted and still disagrees today. Staff has never considered the "cost" of the shaved RTC's to be recognized as a "cost" for determining equivalency with command and control. At the outset of RECLAIM, RTCs were allocated to RECLAIM facilities free of charge, yet they now have value to the facilities as a commodity that can be bought and sold. While RTCs have value, they are not a property right. The proposed amendments to RECLAIM will reduce the number of RTCs. Since there was no cost associated with allocated RTCs for a facility, there should be no financial loss to the RECLAIM universe as the SCAQMD retires them. Any additional purchase of RTCs executed by a facility is made in lieu of emission control. The choice between the RTC purchase and emission control is solely a business decision that is made to generate an expected stream of cost-savings afforded only by the RECLAIM program and not available under command-and-control. Therefore, any RTC investment loss should not be considered as a compliance cost to be compared to the compliance cost under command-and-control regulations. Moreover, this loss may be offset by any potential increase in RTC price due to a decreased RTC supply, which would subsequently raise the market value of a facility's remaining RTC holdings. Finally, any loss of "value" of shaved RTCs cannot be compared to command and control, because in that case, there are no RTCs and thus no similar "value" was ever created.

4) **Many unused RTCs are the result of shutdown selloffs, which have caused undue delay of BARCT-equivalent level of actual NOx emission reductions:** According to staff analysis of the RECLAIM transaction records, many of the unused RTCs were sold, as Infinite-Year-Blocks (IYBs), to operating RECLAIM facilities by some of the now-closed facilities prior to facility closure. These excess RTCs have been artificially depressing RTC prices and have induced RECLAIM facilities to delay the installation of cost-effective controls. A case in point is the 2005 NOx RECLAIM amendments. Despite 7.7 tpd of NOx RTC shave being implemented over the period of 2007-2011, only 4 tpd of actual NOx emission reductions had occurred by the end of the 2012 Compliance Year. Some of the 4 tpd of actual reductions came

from operational changes at refineries, which chose to run gas turbines instead of higher-emitting boilers at various points in time. However, just less than two thirds of the 4 tpd actual reductions were due to facility shut-downs and not measures taken to reduce actual emissions by facilities in the program. In 2005, the shave amount was partially based on the BARCT analysis that included the installation of 51 SCR units at refineries. However, not one has been installed due to the RECLAIM program. (Four SCR units were installed only due to orders for abatement.) While that choice did not violate RECLAIM, it resulted in facilities not achieving the level of emissions they would have achieved had they applied BARCT. As a result, there is a need to ensure that the currently proposed shave is sufficient to induce emission reductions equivalent to 2015 BARCT levels, accounting for growth to 2023.

The original intent of RECLAIM, or any cap-and-trade program, is for all participating facilities to benefit from the differential in each operating facility's ability to cost effectively reduce emissions. It is not to shift a closed facility's prior pollution credits to any facility still in operation and cause undue delay of BARCT-equivalent level of actual NOx emission reductions. (Under command-and-control, any pollution credits from a shut-down facility would at least be discounted by BACT.) As a result, staff proposes this level of BARCT-based shave to substantially reduce the amount of unused RTC credits in the market in order to better ensure the timely implementation of BARCT as required under state law.

Response 1-6 NEC Study

Staff disagrees with the commenter's suggestion that the BARCT cost analysis for the refinery sector needs to be revised to explicitly consider the findings presented by the Norton Engineering Consultants (NEC). First of all staff and NEC both obtained the same average cost effectiveness for refineries. Table 6.1.6 summarized the differences in staff's and NEC's findings in each category of sources:

Total difference in emission reductions: 6.00 tpd (staff) – 5.67 tpd (NEC) = 0.33 tpd
Total difference in PWVs: $629 million (staff) - $562 million (NEC) = $67 million
No difference in average cost-effectiveness for refineries = $11 K per ton (NEC and staff).

Secondly, staff has reduced the proposed shave by 0.85 tpd to more than account for the difference in 0.35 tpd shown above and provide additional compliance margin. The cost-effectiveness value of $11 K per ton estimated by both NEC and staff is lower than the estimated $16 K per ton for the Control Measure CMB-01 in the 2012 AQMP. [19]

The difference between the two analyses occurs in the category of boilers/heaters. Staff's estimates resulted in 0.33 tpd more emission reductions because 35 more heaters that were considered cost-effective compared to NEC's estimates because NEC and staff used different cost

[19] Page IV-A-58, Appendix IV-A, and Table 6-4 of 2012 AQMP.

data to estimate cost. Staff believes its proposal was reasonable since its approach utilized information in the facility permits, information provided by the refineries through the Survey, and information provided by several prominent manufacturers of control devices for each specific category of sources. NEC used a verbal quote for one FCCU SCR to derive the costs for FCCUs, boilers/heaters and SRU/TG applications. The SCR catalysts for FCCU are not the same as the catalysts for boilers/heaters and SRU/TG applications. Nevertheless, staff added 0.8 tpd to the remaining emissions (i.e. reduced the shave by 0.8 tpd) to allow for this difference. Further explanations are provided in Response 1-6 for FCCUs and Response 1-7 for boilers/heaters.

Table Z.1-6 – Differences in Staff's and NEC's Findings

Category	Proposed BARCT	Emission Reductions	Cost Effective Units	PWVs	Incremental Cost Effectiveness DCF (note 1)	Conclusion
Boilers and Heaters with SCRs	No difference 2 ppm	Staff = 0.94 tpd NEC = 0.61tpd Diff. = 0.33 tpd	Staff = 83 units NEC = 48 units Diff. = 35 units	Staff = $242M NEC = $162M	Staff = $28K/ton NEC = $29K/ton	0.85 tpd shave reductions (note 2)
FCCUs with SCRs	No difference 2 ppmv	No difference 0.43 tpd	No difference 5 FCCUs (note 3)	Staff = $152M NEC = $211M (note 3)	Staff = $18K/ton NEC = $25K/ton	No difference
SRU/TGTUs with SCRs	No difference 2 ppmv	No difference 0.32	No difference 9 SRU/TGTUs	Staff = $83M NEC = $96M	Staff = $28K/ton NEC = $33K/ton	No difference
Gas Turbines with SCRs	No difference 2 ppmv	No difference 4.14 tpd	No difference 11 gas turbines	Staff = $98M NEC = $53M	Staff = $3K/ton NEC = $1K/ton	No difference
Coke Calciner with LoTOx	No difference 10 ppmv	No difference 0.17 tpd	No difference 1 coke calciner	Staff =$54M NEC =$39.5M	Staff = $35K/ton NEC = $25K/ton	No difference
Total		**Staff = 6.00 tpd NEC = 5.67 tpd**	**Diff. = 35 heaters**	**Staff = $629M NEC = $562M**	**Staff = $11K/ton NEC = $11K/ton**	**0.85 tpd shave reductions (note 2)**

Note: 1) Ratio LCF/DCF = 1.6, e.g. $1K/ton DCF = $1.6K/ton LCF. 2) Staff provided 0.85 tpd reductions in shave to account for uncertainties in cost analysis assumptions for boilers/heaters and additional compliance margin. 3) Refinery 4 FCCU is scheduled to be shut-down in 2017-2018 which would result in lowering the costs estimated for this category.

As shown in this table, except for boilers/heaters, the same equipment was identified as cost-effective regardless of whether NEC costs or staff estimated costs were used, so there is no difference in calculated BARCT emission reductions. In the socioeconomic report, staff used the high end of the total costs.

Response 1-7 NEC Study for Boilers/Heaters

WSPA ~~sasserts~~asserts that because only a few boilers and heaters are currently equipped with SCR are currently meeting 2 ppmv NOx, this level cannot be BARCT.

NOx Feasible Level

First, it is important to note that staff is obligated to find technology that can reduce maximum amount of pollution to help the basin achieve the ozone and PM2.5 standards and meet the requirement sated in H&SC §40406:

> "… *an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, & economic impacts by each class or category of source*."

The two criteria required to be considered for BARCT are 1) technologically feasible and 2) cost-effective. The feasible and cost-effective control technology must be considered BARCT even if they are not yet operational in the District. In this case, WSPA admits that some units are currently achieving 2 ppmv which is strong evidence that this level is achievable. Staff is not required to focus only on achieved-in-practice and fully commercialized control technology (i.e. technology that is either being offered commercially by vendors or is in commercial demonstration or licensing)[20]. Staff can use a control technology that has been previously installed and operated successfully at a similar type of source, or has potential for application to the source (i.e. has been successfully applied to similar sources with similar gas stream characteristics). For boilers/heaters category, staff included the analysis for SCRs as well as Great Southern Flameless and ClearSign as shown in Appendix B of the PDRS.

Contrary to the commenter's understanding, the H&SC does not specify any threshold on the number of units that must be proven achieved-in-practice for a control technology to be considered feasible. [21]As an example, in the 2010 SOx RECLAIM amendment, staff assessed and determined that a level of 10 ppmv SOx was feasible and cost-effective for a sulfuric acid plant using wet gas scrubber technology even though there was no sulfuric acid plant that had yet achieved this level. The sulfuric acid plant installed a wet gas scrubber in 2011 after the rule was amended, source-tested the unit, and demonstrated that the unit met a level much less than 10 ppmv.

Regarding the count of boilers/heaters, based on information received from the refinery Survey, 14 heaters using refinery fuel gas were reported to achieve 1.6 - 3.5 ppmv NOx with SCRs (Table B.3 of Appendix B). Four of the 14 heaters were reported to achieve 1.6 ppmv NOx. The heaters' maximum ratings are 88, 125, 177, and 199 mmbtu/hr. Based on information in the permit applications, three heaters were first installed in 1970, the fourth heater and the SCR were installed

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[20] American Coatings Assoc. v. SCAQMD, 54 CAL. 4TH 446 (2013)

[21] American Coatings Assoc. v. SCAQMD, 54 CAL. 4TH 446 (2013)

in 1994. In 2004, all four heaters were modified to increase the overall heaters' capacities, and thus all 4 heaters were subject to a permit limit of 5 ppmv NOx. It should be noted that the SCR has been in operation for 21 years and still achieves a level below 2 ppmv NOx. Thus, it is reasonable for staff to consider 2 ppmv as a feasible BARCT level.

It seems that the WSPA/ERM's confidential survey in March 2015 reported different information than the information in the permits. It indicated that only 2 of the 4 heaters were retrofits and the remaining 2 heaters were new.

As stated above, besides SCRs, staff has also identified other control technologies that can potentially achieve 2 ppmv NOx level such as Great Southern Flameless, ClearSign, and LoTOx. A crude heater manufactured by Great Southern Flameless installed at the Coffeyville refinery in Kansas achieved 3-8 ppmv NOx without the use of SCR. Two boilers using natural gas equipped with LoTOx achieved 2-5 ppmv. ClearSign has recently signed a contract with Tesoro to retrofit a heater at Tesoro refinery and hopefully this project can be proven to achieve 2 ppmv NOx without the use of SCR. Great Southern Flameless, ClearSign, and several prominent SCR manufacturers provided staff the estimated costs of control equipment that can be designed to achieve 2 ppmv NOx.

Response 1-8 FCCUs

WSPA contents that staff should not set a BARCT level of 2 ppmv NOx for FCCUs because only one FCCU is currently achieving this level. Staff is required to find technology that can potentially reduce maximum amount of pollution to meet the requirement stated in the H&SC §40406 and help the basin achieve the NAAQS for ozone and PM2.5. Although staff recognizes that there are differences among different refineries, both staff analysis and NEC's analysis identified 2 ppmv as achievable BARCT for FCCUs.

Staff has evaluated two potential control technologies for FCCUs, SCRs as well as scrubber/LoTOx and estimated the cost-effectiveness values for both technologies to ensure that the control technologies were cost-effective. The SCR and LoTOx/scrubbers manufacturers confirmed that 2 ppmv is feasible and provided cost information for the cost analysis.

Each refinery may have unique circumstances (e.g. equipment type, age) and different upstream configuration, however the downstream control equipment such as LoTOx/scrubber and SCR can be designed to achieve the 2 ppmv level as confirmed by the manufacturers and agreed by NEC.

There is precedent in identifying controls based on achievements by a single FCCU at the time the rule adoption. For example, in previous rule development in the SCAQMD, only one FCCU had achieved the BARCT level of Rule 1105.1 at the time the rule was developed.[22] Likewise, only one FCCU in the Basin had achieved the BARCT level of 5 ppmv SOx at time the rule was amended in 2010.

Regarding SCR costs, staff estimated a range of $152 million (no markups) to $163 million (with two layers of markups used by NEC). NEC estimated $211 million (with different feed rates.) NEC's estimates were about 40% higher than staff's estimates. The SCRs were cost-effective at 2 ppmv using either NEC's or staff's estimates. The cost effectiveness for FCCU SCRs has a range of $18K/ton - $25 K/ton.

Response 1-9 Costs and Cost Effectiveness Analysis

This comment asserts that staff's BARCT analysis should be changed because NEC estimated higher costs for certain equipment.

Cost Effectiveness for Refinery Sector

The costs and cost-effectiveness values for each individual class or category of sources are summarized in Table 6.1.6. The overall weighted average cost-effectiveness for the refinery sector based on NEC's and staff's estimates is $11 K per ton DCF ($18 K per ton LCF) with SCR technology, which is well below the thresholds that the commenter cited for the BACT Guidelines and the 2012 AQMP.

Since RECLAIM achieves its reductions in the aggregate rather than based on individual equipment, it is appropriate to look at cost-effectiveness in the aggregate using total program costs and total program reductions.

This comment also asserts that staff should have used the LCF methodology. Staff used a threshold level of $50,000 per ton DCF to exclude individual equipment from the BARCT analysis to be consistent with the SOx RECLAIM amendment in 2010. The cost-effectiveness values based on DCF and LCF methods are not directly comparable to each other: DCF discounts all future operation and maintenance costs to their present values whereas LCF amortizes the initial capital and installation costs over the equipment lifetime. This is why DCF values are always lower than LCF values for the exact same amount of estimated compliance cost. Due to this methodological difference, staff disagrees with the commenter's claim that the same cost effectiveness threshold should be used for both DCF and LCF methods. If the threshold for DCF was $50,000 per ton, the threshold for LCF should be about $80,000 per ton.

[22] Rule 1105.1 – Reduction of PM10 and Ammonia Emissions From Fluid Catalytic Cracking Units, Adopted November 7, 2003.

Cost Effectiveness Thresholds in BACT Guidelines

The commenter cited a threshold in the BACT Guidelines of $19,100 per ton NOx reduced. It should be noted that this threshold was estimated in the 2nd quarter of 2003 and should be adjusted to $28,000 per ton as of 2015 dollars. The threshold considers the difference in costs and emissions between a proposed BACT and an uncontrolled case. The commenter however should cite the threshold for “incremental” cost effectiveness which looks at the difference in costs and emissions between a proposed BACT and a less stringent control level. The threshold for “incremental” cost effectiveness is $57,200 per ton as of 2nd quarter 2003 and should be adjusted to $80,000 per ton as of 2015 dollars. This is a more appropriate comparison when looking at two possible incrementally different levels of control.

More important, these thresholds are for equipment located at non-major polluting facilities (also known as minor sources BACT, or MSBACT, in Part C of the BACT Guidelines). There are no thresholds for sources located at major polluting facilities such as the refineries, BACT/LAER is required without any cost consideration for sources located at major polluting facilities (Part A and B of the BACT Guidelines).

Cost Effectiveness for Entire Proposed RECLAIM Project (Refinery and Non-Refinery)

This comment further asserts that RECLAIM facilities may be being treated disproportionately compared to facilities under command-and-control by having higher cost effectiveness. First of all, it is necessary to look at the RECLAIM program as a whole since H&S Code 39616 (c)(7) refers to “disproportionate impacts measured on an aggregate basis” on sources in RECALIM. As shown below, the cost effectiveness for the entire RECLAIM project, including refinery and non-refinery, ranges from $7K - $12K per ton.

The PWVs for the entire NOx RECLAIM project as shown in Tables 4.3 and 4.4 (w/o cement kilns):

Low end: $565 million (refinery) + $163 million (non-refinery) = $728 million
High end: $923 million (refinery) + $176 million (non-refinery) = $1099 million

Total emission reductions: 6.00 (refinery) + 2.77 (non-refinery) = 8.8 tpd

The overall range of cost-effectiveness for the entire RECLAIM project:

Low end of range: 728,000,000/8.8/25/365 = $9,066 per ton
High end of range: 1,099,000,000/8.8/25/365 = $13,686 per ton

Table Z.1-9 Cost Effectiveness Comparison

	Cost Effectiveness ($/ton)
Proposed Amendment	9,066 – 13,686
Control Measure CMB-01	7,950 (Phase I) – 16,000 (Phase II) [23]
Threshold in BACT Guidelines for “Minor Sources”	80,000 [24]
2012 AQMP	22,500 [25]

As shown in Table Z.1-9, the cost-effectiveness for this proposed NOx RECLAIM amendment is less than the thresholds that the commenter cited for the BACT Guidelines and the 2012 AQMP. They are also within the average cost effectiveness estimated for Control Measure CMB-01 in the 2012 AQMP.

Moreover, the NOx cost-effectiveness threshold of $22,500 proposed in the 2012 AQMP was intended as a threshold above which tiered levels of analysis would be conducted. It was not intended as a threshold above which a control measure would automatically be excluded. Therefore, this threshold should not be used to determine whether proposed rules or amendments would be cost effective.

In conclusion, it is conservative in using a threshold of $50,000 per ton for “incremental” cost effectiveness to eliminate cost-ineffective individual scenarios.

Response 1-10 Costs and Cost Effectiveness Analysis

This comment asserts that NEC conducted a comprehensive evaluation of site-specific factors for each refinery, which staff did not appropriately consider. However, staff has maximized the use of site specific information provided by NEC on installation, design, engineering costs, space needed, plant configuration, equipment type, equipment age, length of time for SCR to operate and remain in service, and time needed for construction.

As explained in response 1-6, in only one case did NEC reach a different conclusion than staff regarding the appropriate BARCT (boilers/heaters). For that category, staff removed the emission reductions associated with equipment that was cost-effective under staff’s analysis but not under NEC’s analysis from the BARCT reductions (0.33 tpd. In fact, staff actually removed 0.8 tpd from the proposed shave.) The socioeconomic report gives appropriate consideration to the higher end of total BARCT costs.

[23] Table 6-3 and 6-4 of the 2012 AQMP, and page IV-A-13 and page IV-A-58, Appendix IV-A of the 2012 AQMP
[24] “Incremental” cost effectiveness on page 29 of the SCAQMD BACT Guidelines, dated July 2006, adjusted to 2005 dollars
[25] Cited by the commenter, page 4-43 of the 2012 AQMP, February 2013

This commenter further asserts that staff did not properly consider installation, design, and engineering costs and that what is cost effective at one refinery may not be at another. Again, NEC confirmed, after visiting the sites, that staff's proposed BARCT was appropriate for all cases except refinery boilers/heaters, described above. Staff looks forward to receiving the additional information WSPA states that it will submit.

Response 1-11 Disproportionate Impacts

This comment asserts that RECLAIM facilities may be disproportionately impacted because non-RECLAIM facilities represent the majority of stationary source NOx emissions yet the District does not appear to be seeking reductions from them. The commenter also argues that reductions from non-RECLAIM sources must be "proportionate".

It is incorrect to assert that staff is not seeking reductions from non-RECLAIM sources. Staff is seeking emission reductions for all sources, RECLAIM and non-RECLAIM, where feasible and cost-effective control technologies are available to help the basin achieve the ozone and PM2.5 ambient air quality standard as expeditiously as possible.

Even though RECLAIM sources collectively account for 27 tpd NOx emissions while non-RECLAIM sources such as residential fuel combustion, waste disposal, and miscellaneous processes together account for 46 tpd, RECLAIM is the fourth largest source of NOx emissions in the Basin and the top #1 emitting stationary source. There is no requirement to reduce NOx emissions from all sources at the same time. Nor is there any requirement that all sources must reduce emissions "proportionately", i.e. by the same percentage.

Instead the law requires the District to seek BARCT-level reductions from all existing sources. BARCT is not a fixed percentage such as 40% or 50% reductions. Instead, it is defined as the maximum level of reductions achievable for each class or category of sources. For example, some equipment may be already relatively low-emitting so the maximum achievable reductions may be a smaller percentage, and some equipment may not have a cost-effective option available that will achieve the same percentage reduction as the RECLAIM sources. As long as each category implements the maximum reductions achievable for that category, there is no disproportionate impact.

Staff has continually sought BARCT NOx emission reductions from all sources, large and small. Recent examples include Rules 1110.2 (engines), 1146, and 1146.1 (boilers, heaters, steam generators) and Rule 1147 (miscellaneous NOx sources). The District has regulated sources as small as residential water heaters (Rule 1121).

Furthermore, the control technologies that can reduce emissions from RECLAIM sources are commercially available and some are achieved-in-practice whereas the control technologies for many non-RECLAIM sources are being developed and not yet identified in the 2012 AQMP.

In addition, the RECLAIM program offers many other benefits to the RECLAIM facilities which show that these sources are not suffering disproportionate impacts on an aggregate basis.

— *Source-specific standards.* The non-RECLAIM facilities are subject to source-specific standards (e.g. concentration limit or mass emission limit) and every source (e.g. boiler or heater) at the non-RECLAIM facilities must be controlled to the same concentration limit or mass emission limit, and the source-specific command-and-control limit cannot be exceeded at all times whereas the RECLAIM facilities can operate their equipment with flexibility, they can purchase RTCs from other RECLAIM facilities to reconcile the emissions with the facility caps at the end of the compliance year in lieu of installing control;

— *BACT Discount.* The emissions from shutdown equipment at the non-RECLAIM facilities are required to be discounted to the BACT level before ERCs can be issued whereas the RECLAIM facilities can use or trade the RTCs associated with shutdown equipment without any BACT discount;

— *NSR Offset Factor.* The new or modifying non-RECLAIM facilities undergoing New Source Review (NSR) are required to offset any NOx or SOx emission increase by a factor of 1.2 to 1.0 ratio whereas the RECLAIM facilities are not subject to this offset. Instead, the RECLAIM facilities are required to hold sufficient RTCs based on their maximum potential to emit at a ratio of 1.0:1.0 at the beginning of each compliance year, and they can sell back the unused RTC offset holdings at the end of each compliance year.

— *Flexibility to Install Control.* The RECLAIM facilities have the flexibility to install the least cost controls first, and have the flexibility to use the program averaging and cross-cycle trading to balance their compliance option.

— *Trading.* In addition, the RECLAIM facilities receive monetary benefits from trading their RTCs (equivalent to "Potential-to-Emit") for the past 22-year life of the RECLAIM program to reduce the costs of compliance.

Because of the many benefits available in the RECLAIM program, staff believes that the RECLAIM facilities are not being disproportionately impacted by participating in the program.

Response 1-12 Energy Efficiency Projects

In responses to question #10 of the Survey Questionnaire,[26] the refineries sent to staff the CARB's report released in June 2013.[27] Note that the actual emissions and the RTC holdings have different "currencies". It is very likely that the 2011 emissions baseline already reflects the energy efficiency projects (i.e. 0.7 tpd co-benefit reductions were included in the baseline.) However, The RTC holdings ("Potential to Emit") were last adjusted in 2005, and at that time, the energy efficiency projects were not yet been completed, thus the RTC holdings ("Potential to Emit") have not yet been reduced to reflect the energy efficiency projects. However, staff did not reduce the shave by 0.7 tpd to reflect the co-benefit reductions of the energy efficiency projects because this was used to offset the increase between the 2011 and 2012 emissions baseline for the refinery sector. The information on energy efficiency projects as part of the responses to the refinery Survey should be included in the PDSR.

Response 1-13 Socioeconomic Impacts

Staff is working on the socioeconomic report and the report will be made available soon.

Response 1-14 2012 Compliance Year Emissions Baseline

Staff used the 2011 compliance year emissions as baseline because 2011 is the last year for implementation of the 2005 NOx RECLAIM amendment. Staff estimated the shave based on the remaining emissions projected to the 2023 compliance year. If the compliance year 2011 emissions were used, the growth factor from 2011-2023 will be used to project the emissions to 2023. If the compliance year 2012 emissions, the growth factor from 2012-2023 will be used to project the remaining emissions. Both methods should result in the same 2023 remaining emissions for RECLAIM facilities assuming that the growth factors are projected reasonably accurate to reflect the change in emissions. For the refinery sector, staff used a [WW3][m4]growth factor of 1.0 provided by the refineries since the inception of the RECLAIM program in 1993. The 2012 compliance year emissions are 0.6 tpd higher than the 2011 compliance year emissions, thus the 2023 remaining emissions would be 0.6 tpd higher for refinery sector. However, there are 0.6 tpd co-benefits associated with the energy efficiency projects that were not being taking out of the RTCs holdings in the 2015 NOx RECLAIM amendment which would wash out the effect of the change in baseline year.

[26] Appendix L of the PDSR
[27] Appendix K of the PDSR

Response 1-15 NEC's Cost Analysis

Refer to Responses 1-6, 1-7 and 1-10. On contrary to the commenter's remarks, staff strongly believes the approach used is consistent with the requirements in H&S Codes in evaluating and conducting a technical feasibility and cost-effectiveness analysis for the NOx RECLAIM project. Staff did not ignore NEC's findings. On the contrary, staff has maximized the use of NEC's site specific information on installation, engineering costs, space needed, plant configuration, equipment type, equipment age, length of time for SCR to operate and remain in service, and time needed for construction. Moreover, NEC reached the same conclusion as staff for BARCT for all refinery source categories except boilers/heaters. For that category, staff adjusted the BARCT goal by adding 0.8 tpd to the goal, which is more than enough to account for the emission reductions attributable to equipment that was not cost-effective under the NEC analysis.

Response 1-16 0.85 tpd for Uncertainties

Refer to Response 1-7. Staff believes that providing 0.8 tpd RTCs is sufficient to account for the uncertainties and differences in the analysis related to boilers/heaters which amount to only 0.33 tpd difference in emission reductions between staff's and NEC's analyses

Response 1-17 Regional NSR Holding Account for Non-Electric Generating Facilities

Staff has created a Regional NSR Holding Account to help facilities in the power sector subject to Rule 2005 NSR requirements. Staff has discussed this issue with the U.S. EPA to seek their approval on the concepts. Other facilities have more flexibility than Electric Generating Facilities to reduce their PTE and thus their required RTC holdings if their actual emissions are lower than their PTE.

Response 1-18 Compliance Margin

Refer to Response 1-2 for discussion on compliance margin. The cement plant was shutting down but staff still included 0.29 tpd for the remaining emissions of cement kilns and 0.1 tpd for the remaining emissions of other shutdown facilities. Since the cement plant and other shutdown facilities are not coming back in business, this amount of RTCs will serve as additional compliance margin to the entire NOx RECLAIM universe.

Response 1-19 Across-the-Board Shave

Refer to Responses 1-3.

Response 1-20 Emissions from 219 Facilities

Staff will revise the statement to state:

"The remaining 219 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there is was either no new BARCT for the types of equipment and operation at these facilities (e.g. these facilities do not have FCCUs, coke calciner), or limited amount of emission reductions that could be achieved (less than 0.1 tpd for ICEs and small boilers/heaters).

Response 1-21 Implementation Schedule

Staff believes that the amount of unused RTCs in the market can support 4 tpd early reductions in 2016, and extending one more year from 2022 to 2023 may not be necessary.

Response 1-22 Longer Public Participation

Staff has been conducted public meetings on the proposed NOx RECLAIM for almost 3 years, and staff is planning for a public hearing in November 2015. The CEQA and socioeconomic analyses would be released for public comments according to the requirements in the H&SC §40440.5.

Response 1-23 Energy Efficiency Projects

Refer to Response 1-12.

Response 1-24 CEQA Alternatives

The size of the shave to represent 3-5 tpd of Control Measure CMB-01 of the 2012 AQMP would be about 11% - 19%, between the "No Project" Alternative (0% shave for Alternative 4) and the "Industry Proposal" Alternative (33% shave for Alternative 3).

Response 1-25 Cost Analysis

Please refer to Responses 1-5, 1-9, and 1-10.

Response 1-26 Useful Life 25 Years
Refer to Response 1-4.

Response 1-27 DCF versus LCF Cost Effectiveness

Refer to Response 1-9.

Response 1-28 Reductions and Remaining Emissions

Refer to Response 1-2 for the response addressing remaining emissions, Control Measure CMB-01, shave methodology, and the necessity to seek for more than 5 tpd reductions as estimated in Control Measure CMB-01. Refer to Response 1-11 for the response addressing disproportionate impacts. Refer to Responses 1-5 for the response addressing H&S Code 39616 requirements.

Response 1-29 Compliance Margin

Refer to Response 1-2. In addition, WSPA's comment admits that the program has functioned on as little as 15% compliance margin, and has not shown any need for the much longer amount of excess RTCs allowed by the industry's proposal.

Response 1-30 Remaining Emissions for Refinery Sector

Refer to Responses 1-6 and 1-7. NEC identified the same BARCT for all refinery categories except boilers/heaters. Staff provided 0.8 tpd reductions in shave to account for comments received from stakeholders regarding uncertainties in the BARCT analysis and thus provide additional compliance margin. Staff is required to show incremental cost effectiveness for the entire category of source and not for individual equipment. Thus, incremental emission reductions = 0.43 tpd (incremental emissions from 2005 BARCT) and incremental PWVs = $152 - $391 million for the FCCU category.

Response 1-31 Appendix A - FCCUs

Refer to Response 1-6.

Response 1-32 Appendix B – 2 ppmv Level for Boilers/Heaters

Refer to Response 1-7. The count of boilers/heaters presented at the September 19, 2013 Working Group Meeting (9 heaters having NOx emissions between 1.6 – 5 ppmv) was updated at a later date. The updated list in the PDSR showed 14 heaters with NOx emissions between 1.6 – 3.5 ppmv. Furthermore, the level of 2 ppmv not 3.5 ppmv should be considered as BARCT since it is "*…an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy & economic impacts by each class or category of source*".

Response 1-33 Appendix B – NEC's Analysis for Boilers/Heaters

Refer to Response 1-7. Several heaters have already achieved this level presenting strong evidence that it is achievable. The difference in emission reductions between the two estimates was only 0.35 tpd and staff provided 0.85 tpd reductions in RTC shave to account for uncertainties in the assumptions of the cost analysis and additional compliance margin.

Response 1-34 Appendix B – Cost Analysis for Boilers/Heaters

Staff does not understand the comment. The "programmatic" overall average cost effectiveness for boilers/heaters category is $27,529 ton NOx reduced as shown in Table B.11, page 77 and Table 4.3. Refer to Table 6.1-6 for comparison between NEC's and staff's estimates. Also, refer to Response 1-7.

Response 1-35 Appendix D – Coke Calciner

This comment supports staff recommended BARCT for this category. No response is needed.

Response 1-36 Appendix E – SRU/TGs Applications

NEC's cost analysis does not alter the BARCT conclusion for SRU/TG applications. There were no differences in emission reductions between the two estimates. NEC's estimates of costs were 16% higher than staff's estimates. SCRs were cost-effective with NEC's and staff's estimates of costs. See Table 6.1-6.

Response 1-37 Appendix K – Energy Efficiency Projects
Refer to Response 1-12

Response 1-38 Shave Approach
Refer to Response 1-3.

Comment Letter #2 – NEC's Letter Dated August 10, 2015

Comment 2-1 FCCU SCR Costs

NEC stated that they agreed that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats….. NEC believed that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but NEC and staff have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

Response 2-1

Staff concurs that there may need to be a change from current SCR designs in order to achieve the 2 ppmv. As presented in the Preliminary Draft Staff Report (PDSR), the SCR profile for the refinery FCCU SCRs currently installed relies on 2-layers of catalyst. The NEC model is scaled to operate using 3-catalyst layers. This merely reflects a difference in engineering approach. NEC is arguing that the third bed is needed for reliability, however Refinery 1 has operated their FCCU SCR with two beds of catalysts and achieved less than 2 ppmv NOx since 2003 and several manufacturers provided costs based on SCR applications using a 2-layer catalyst bed that meet the proposed 2 ppmv BARCT emissions level, thus staff believes that 2 layers of catalysts are sufficient. The NEC model is not based on or proposed for a specific SCR application, but instead provides a configuration that will achieve the same reductions. The resulting technical specifications between the two approaches are different, whereby the SCR box size, catalyst volume, and layer configuration, among other aspects of installation, account for the difference in cost estimates. However, the potential additional cost to enhance SCR designs does not impact the total proposed reduction in RTC holdings.

Comment 2-2 Basis for Catalyst Addition and Velocity Reductions vs Vendor Budget Quotes

All FCCU SCR catalyst beds are in the range of 3 - 4' deep, all are prone to plugging by catalyst and/or ABS and all have limitations on allowable pressure drop, so superficial velocity is a good basis for comparison between units. The district has three operating FCCU SCRs. All units have two catalyst beds and operate at superficial gas velocities in the range of 8 to 13 ft/sec. Two of the three units, operating at superficial velocities of 12 and 13 ft/sec do not achieve emissions of 2 vppm @ 3% O_2. The other unit, highlighted in the draft report, achieves less than 2 vppm @ 3% O_2 operating at a superficial velocity of 7.7 ft/sec. The "good" unit is operating with inlet NOx levels which are 50% of design or lower and at lower than design flue gas flows. There are several ways to bring the two "non-performing" units into compliance with the revised standard, each with different costs and different overall performance impacts. NEC was not commissioned to do an evaluation of individual units and propose improvement options, but rather to make an assessment of what it would take, cost wise, to reliably achieve the 2 ppmv limit for grass roots SCR installations. Based on the experience of operating units in the district, and our direct experience with FCCU units for other clients (due to confidentiality agreements we cannot divulge client identities and specific locations) reliably achieving 2 vppm NOx emissions in an FCCU over a five year run will require the addition of catalyst and will be designed for superficial velocities of 10 ft/sec or less. Considering that SCR catalyst vendors have not developed and guaranteed a specific SCR design for 2 ppmvd @ 3% O_2 NEC feels that it is prudent to assume that a third bed of catalyst (SCR or ASC) and cross section designed to achieve a maximum superficial velocity of 10 ft/sec is sufficient to characterize the most likely cost of a SCR unit capable of achieving 2 ppmvd in a typical refinery FCCU environment. The impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation has been overstated by district staff as a 284% increase in catalyst volume over manufacturer's estimates. The increase over manufacturer's budget estimates/proposals is actually 92%, one half of staff's reported delta.

Response 2-2

Staff understands the reasoning behind NEC's methodology in determining the impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation. A review of Item 1 on page 121 of the PDSR indicated that the "total catalyst volume" was incorrectly stated and should have read "total SCR volume." and was followed by an incorrect projected catalyst volume and space velocity. It is important to note that the NEC reports did not directly state the height of the catalyst layer within each SCR layer but referred to the SCR layer as 11 ft. Correspondence with NECs staff indicated that the catalyst layer height would be less than 55% of the SCR layer height and subsequent conversations with NEC projected the catalyst layer height within the range specified above. The uncertainty in the catalyst layer height may have contributed to the incorrect calculation of catalyst volume presented in the PDSR assessment in Appendix F. We concur that the increase over manufacturer's budget estimates/proposals is approximately 92 percent and the next version of the staff report will corrected.

Comment 2-3 Staff's SCR Design Comparison Did Not Accurately Reflect NEC's "Typical" FCCU SCR Design

Staff used an incorrect basis for comparing NEC's typical FCCU SCR with district units in Table F.3. A revised comparison, using data from Refineries 1, 5 and 6 is shown below.

Table 1 (F. 3 Showing NEC Typical SCR)
Performance Information of Existing SCRs

	Refinery 1	Refinery 5	Refinery 6	NEC Typical
FCC Feed Rate, kBPD	95	71	84	55
SCR Inlet Flue Gas Flow, ACFS	6,585	5,525	9,685	3,848
SCR Manufacturer	1	3	2	--
No. Catalyst Layers	2	2	2	3
Catalyst Volume, ft^3	6,200	2,975(1)	6,200(5)	4,600
Design Inlet NOx, ppmv	133(2)/40-80(3)	150	35	45
Design Outlet NOx, ppmvd	--	17	6	2
NOx Measured, ppmvd	<2	15-17	5.6 – 6.4	1.5 (Est.)
Superficial Gas Velocity, fps	7.4	13.3	11.6	10.0
Space Velocity, 1/hr	3,823(6)	6,686(4)	5,624(5)	3,011
Removal Efficiency	95 - 97%(3)	89%	83%	97%

Notes:

1. Staff incorrectly stated catalyst volume as 2,391 ft3 in Table F.3. 2,975 ft3 catalyst volume confirmed by NEC with Refinery 5 and via review of SCR data provided by Refinery 5 to SCAQMD.
2. Design value reported as 155 ppmv @ 0% O2. Value presented in table is corrected to 3% O2.
3. Measured outlet NOx value of <2 ppmv corresponds to operation of unit with inlet NOx in the range indicated. Removal efficiency based on range of actual operation.
4. Staff reports space velocity value of 2,974/hr in table F.3.
5. Confidential data provided by SCAQMD staff is insufficient to calculate the catalyst volume for this unit without making the following assumption on the depth of a catalyst module which we assume to be 45". Staff used ½ of this value in Table F.3 corresponding to catalyst bed depth (catalyst element height) of 22.5". Recommend staff confirm catalyst volume with Refinery 6.
6. Confidential data on unit design and performance, provided by SCAQMD staff, used to calculate inlet volumetric flow and space velocity. Values differ from staff's entries in Table F.3.

Response 2-3

Staff has looked over the values presented in the abovementioned revised comparison. It is difficult to confirm several of the values presented in this table and the notes. It is also important to note that the PDSR did not include the NEC model (proposed to achieve a 2ppmv emissions limit) in F.3. Staff referred to the 3-catalyst layer NEC approach that was presented in the Non-Confidential Final Report. The NEC data were encumbered in the Confidential Reports as a model for scaling FCCU SCR specifications and costs to the appropriate FCCU application. Furthermore, it should be noted that staff did not estimate the catalyst volumes or space velocities for Refinery 1, 6 or 5 as NEC stated in the footnotes of Table 1 above. The numbers included in the PDSR were either reported by the refineries through the Survey or documented in the permit applications. Staff confirmed with Refinery 6 on the FCCU SCR catalyst volume and Refinery 6 reported the catalyst volume was not 6,200 cubic feet as estimated by NEC in Table 1 above.

In addition, it is important to note that staff's analysis in the PDSR relied on the manufacturers' cost data provided to staff which did not project based on any specific superficial gas velocity or space velocity. The manufacturers provided costs based on a profile of the SCR currently used at Refinery 1 that rely on 2 layers of catalysts to meet 2 ppmv BARCT level. The bottom line is that NEC's added cost based on a design including 3 layers of catalysts would not affect the overall conclusion on the cost-effectiveness of the FCCU SCRs and would not impact the total proposed reduction in RTC holdings.

Comment 2-4 NEC's "Typical" FCCU SCR Design

In their review, staff is suggesting that NEC's typical SCR is overdesigned and as a result overpriced. Staff's comparisons suggest an overdesign factor of as much as 284%. We do not agree with this assessment. As can be seen in Table 1 (shown in Comment 2-3) , NEC's typical SCR should be able to achieve 97% NOx reduction by virtue of the addition of catalyst at higher gas velocities than the SCR operating at Refinery 1. The typical SCR design provides an approximate 21% margin in space velocity over the Refinery 1 SCR design primarily due to the addition of a third catalyst bed. The addition of a third bed has inherent performance advantages in that it provides for partial redistribution of unreacted NH_3 and NOx versus further cross sectional area additions. If it is determined that the incremental cost of specially fabricated catalyst modules (shorter depth) is low, some further optimization may be possible to reduce SCR cost. It is worth noting that the ~21% catalyst margin will have a 12% overall TIC and PWV cost impact.

Response 2-4

In reexamining our evaluation, staff agrees that your typical SCR is not overpriced. Staff also understands the reasoning for your selection of a third catalyst bed, and as previously discussed, the PDSR erred in catalyst volume calculation. However, even with a 3rd catalyst bed the change in overall cost-effectiveness would not impact the total programmatic shave. Staff will continue to utilize our approach in deriving the costs based on the manufacturers' information and Refinery 1's profile of 2 layers of catalysts to meet 2 ppmv BARCT level.

Comment 2-5 Mark-up factor 1.35

The following paragraphs provide background for NEC's use of a 35% conditioning factor for vendor equipment quotes at early stages of projects. These concepts were discussed with SCAQMD staff during reviews of our report and in subsequent follow-up phone conversations and e-mails. Due to the extensive discussion around this topic we are mystified by staff's characterization of this "bid conditioning factor" as, and here I paraphrase, 'an undefined and therefore invalid cost increase'.

Obtaining budgetary quotations from vendors for their equipment is part of the process of developing cost estimates for any project. At the early stages of projects, or when general information is sought, vendors are not provided comprehensive design basis information and therefore do not have a complete picture of the operating envelope for their proposed equipment. In these instances, some vendors will use costs from recent projects and "factor" them to the provided process conditions, other vendors may develop estimates based on equipment designed specifically to meet the provided process conditions. In either eventuality, the vendor is providing a quality estimate with reasonable accuracy (about +/- 10%) for the specified process conditions, without providing a performance guarantee and without review of the specific codes and standards applicable to refinery installations.

As project definition improves the process basis becomes fixed, equipment sizes become more reliable, performance guarantees are finalized, and vendor quote accuracy improves. Industry experience shows that at the early stages of a project, basis uncertainty alone, necessitates the addition of a 15 – 25% conditioning factor to a vendor's budget quote, in addition to other bid conditioning factors, to account for the difference seen between early equipment bids and final, full definition, performance guaranteed, equipment bids based on a definitive project basis.

Refineries are built to a more rigorous set of standards than typical air pollution control equipment which makes projects in the refining sector slightly more expensive than typical industrial projects. Standards which will have an impact on either the SCR design, the structural support design, location of equipment, internal and external maintenance access, etc., are likely to increase Direct SCR M&L costs. At this stage of project definition a factor of 10% is added to a vendor's equipment bid to account for the cost of meeting local plant standards.

The 1.35 "mark-up" or bid conditioning factor used in NEC's cost work-up for all SCR projects (FCCU, Heaters/Boilers, etc.) is not an arbitrary factor used to inflate costs, as implied in Appendix F, but is actually the low end of a time tested and proven means to determine the actual cost of a piece of equipment after full project definition is complete, including application of local industry standards to the design of the equipment, performance guarantees are offered and firm pricing for equipment components is provided by the vendor.

Response 2-5

Staff appreciates the in-depth background information of the bid conditioning factor, and regret the inclusion of language characterizing the use of the factor as "invalid". The PDSR approach relies on the EPA model defined in Appendix A with a 50% contingency factor added to the cost estimate. However, staff recognizes NEC's expertise in evaluating costs to place equipment in operation, but we will continue to utilize our approach in deriving the costs and will present your derived results for comparison. Staff derived the SCR costs for Refinery 5, 6 and 7 based on

Refinery 1 actual costs, thus the bid conditioning is not applicable here. For Refinery 4 and 9, the SCR costs were based on the costs provided by several prominent manufacturers and since SCR is a mature technology, staff feels that a 50% contingency factor is sufficient. Even if the bid conditioning factor was used, staff's estimates would be $163 million for 5 SCRs at Refinery 5, 6, 7, 4 and 9 (Appendix F) compared to $211 million as estimated by NEC. The bottom line is that NEC's estimates of $211 million would not affect the overall conclusion on the cost-effectiveness of the FCCU SCRs and would not impact the total the total programmatic shave.

Comment 2-6 75% increase in labor to the costs of the SCR

Another cost factor discussed with SCAQMD staff, and apparently dismissed as a simple adder to make costs appear high, is the cost of actually installing the equipment supplied by the SCR vendor in the plant. The vendor does not do construction and does not quote the cost of field assembly in their quote which only covers fabrication and supply of the equipment, in this case the SCR catalyst, support frames, ammonia injection grid and the carbon steel box.

The labor cost factor used in NEC's development of project costs is applied to the SCR vendor's factored estimate to account for the labor required to install the manufacturer's equipment at the site, transportation, taxes, tie-ins, insulation, access, structural steel, etc. Installation labor for equipment can range from a low of about 30% of the equipment cost to as much as 200% of direct equipment cost depending on the complexity of the equipment, the material it is made of and other equipment specific factors. In general, low cost equipment manufactured of low cost materials have higher installation percentages than highly complex equipment made of high cost materials. As a reference point, "Applied Cost Engineering", Clark F. D. and Lorenzoni A. B.; Marcel Decker Inc., 1978, uses a factor of 2.2 times direct material costs to estimate the direct M&L cost of a fired heater installation, a factor of 3.0 times direct material costs to estimate the direct M&L cost of a pump installation and a factor of 2.9 to estimate the direct M&L cost of a distillation tower. Due to the simplicity of the SCR equipment and its use of low cost materials we have used an installation labor cost factor of 0.75 (75%) to account for physical installation of the SCR, structural steel, fit-up of ducting, connection of piping, foundations, excavation, instrumentation, insulation, equipment storage, etc. This factor does not account for any costs associated with: demolition of existing equipment, modification of existing equipment, labor inefficiencies attributed to working in an operating plant, relocation and/or modification to underground utilities, piping, piping supports, ammonia storage facilities, control system additions, instrumentation wiring, conduit, power wiring, area paving, area lighting, area utilities, safety facilities, soot blowers, etc.. The cost of these items is rolled up into the overall TIC factor applied to escalate SCR M&L costs to a total project cost.

Response 2-6

As with the bid conditioning factor, staff concurs that the NEC approach which adds a 75% labor cost factor is a valid alternate assessment of the projected project costs. As previously mentioned we will present the information that you used in your assessment but we will continue to utilize our approach in deriving the costs. The PDSR approach relies on the EPA model with a 50% contingency factor added to the cost estimate. The EPA model did not have the 75% labor cost factor. Since the SCR technology is commercially available for more than two decades, staff did not feel that a 75% increase in labor is a necessity. However, as shown in Table F.5, Appendix F, even if the 75% labor cost factor was included, staff's estimates would be $163 million for 5 SCRs at Refinery 5, 6, 7, 4 and 9 compared to $211 million estimated by NEC. The bottom line is that NEC's estimates of $211 million do not affect the overall conclusion on the cost-effectiveness of the FCCUs and do not impact the total the total programmatic shave.

Comment 2-7

SCAQMD staff disputes NEC's use of a TIC factor of 4.5 to convert direct M&L costs for the SCR into TIC for the SCR PROJECT. This factor is a reasonable estimate for project items not specifically identified in the direct M&L costs (indirect costs, engineering and owner's costs, labor productivity, ancillary equipment and systems, revamp items, duct work, area paving, lighting, utilities, safety systems, control system connections and programming, instrumentation, soot blowers, etc.) As a point of reference, the TIC factor used by NEC, in this analysis, is 90% of the average TIC factor of 4.9 used to estimate SOx control costs in NEC's SOx RECLAIM report.

Response 2-7

Staff appreciates NEC's position on the TIC factor and agree with the reasonableness behind its selection. After the NEC Non-Confidential Report was posted for review, staff met with refinery personnel and their consultants who provided examples of SCR equipment purchases and installations at out-of-state refineries. Their data supported a 4.0-4.5 factor for PWV evaluation. Appendix A of the PDSR uses the 4.5 factor as an upper bound of cost estimation for the FCCU SCR PWV and cost analysis (i.e. $163 million for SCRs with 2 layers of catalysts). Staff reevaluated the EPA methodology in conjunction with a 50% contingency factor (i.e. $152 million for SCRs with 2 layers of catalysts). Regardless, use of both methodologies provides a range of expected costs.

Comment 2-8

SCAQMD staff is correct in pointing out that NEC used incorrect design capacities in developing the FCCU SCR costs shown in section 1.2 of NEC's non-confidential report (14-045-4, November 26, 2014). NEC back calculated expected FCCU rates from flue gas flow rate data provided by AQMD staff to obtain estimated FCCU sizes. The following table presents a revision to the report table based on corrected FCCU sizes as indicated by district staff. Also included in the table is an update to the cost of a Grass Roots SCR for Refinery 6 based on a comparison of flue gas rates to the SCR versus the typical (base case) SCR. Revised NEC estimates provided in Table 2 do not include any reduction to NEC's original cost estimate model.

Response 2-8

Staff thanks NEC for back calculating the expected FCCU rates from the correct design capacities. However, staff cannot verify some of the assumption in footnote 1 that NEC used for Refinery 6 and thus we continue to present the $211 million that NEC estimated. The bottom line is that NEC's estimates of $211 million do not affect the overall conclusion on the cost-effectiveness of the FCCUs and do not impact the total the total programmatic shave.

Comment 2-9

Staff provided a review of NEC's cost estimates based on a comparison to the cost provided for Refinery 1's SCR to demonstrate that NEC's estimating method is overly conservative. In this comparison staff claims that NEC's cost tool over predicts the cost of this installation by $11M (27%). The difficulty in comparing a specific project to a generalized curve is that the project has a specific scope which in most cases is different than the assumed scope of the "typical" project. This is the case for the SCR installation at Refinery 1 which, according to Refinery 1 personnel, did not include the cost for waste heat boiler modifications. Subtracting this component from the TIC for a typical FCCU SCR installation and recalculating PWV yields a cost of $45.45M which is 10.8% higher than staff's cost work-up on this project of $41M, not the 26% difference indicated in Appendix F. Staff had the WHB cost information NEC used in our estimates, we do not understand why they did not make the PWV comparison on the same basis.

Response 2-9

The PDSR estimation of Refinery 1's PWV was based on data provided by refinery staff. Staff took the data reported by Refinery 1 as the total project cost for the SCR system including all peripheral equipment.

Comment 2-10

Staff also provided a review of NEC's cost estimates based on staff's assessment of differences between the data provided by an SCR vendor to staff and NEC for an installation at Refinery 9. In staff's evaluation of the data provided by the vendor they incorrectly calculate the total catalyst volume to be 3,100 ft^3 vs the actual vendor proposal which provided only 2,400 ft^3. Staff also incorrectly calculates NEC's estimated catalyst volume at 12,697 ft^3 vs an actual value of 4,600 ft^3 (1.92 x vendor proposal, see previous discussion on catalyst volumes and specification of a third bed).

Response 2-10

With regard to your second comment first, staff agrees that the catalyst volume was incorrectly presented in the PDSR. The 12,697 ft3 actually represents the total SCR volume. As presented in the PDSR, the manufacturer's recommendation for the Refinery 9 catalyst volume was 3,300 ft3. A review of the data provided by the SCR manufactures will be conducted to conform to proposed specifications and correct any misrepresentations in the PDSR.

Comment 2-11

NEC provides a few comments on SCAQMD staff's determination of PWVs for FCCU SCRs.

1. In using the costs provided for Refinery 1's SCR staff is assuming that all district SCRs can be installed without any impact on upstream equipment and that installation of the SCR can be executed in an open, non congested area. Refinery 1's SCR was installed prior to the installation of a large ESP, which occurred around 2006. If the SCR was to be installed today, or at any time after installation of the large ESP, costs would be higher due to productivity debits associated with working in a congested area and quite possibly even higher due to the need to move or modify some equipment to make the installation possible. In the most extreme case the SCR and ducting may have to be field erected from small fabricated assemblies due to access constraints.

2. Staff used a 0.7 power factor to scale the costs for Refinery 1's SCR project to different sizes. Costs for FCCU regenerator flue gas systems scale more accurately when a figure of around 0.6 is used. The effect of using a larger scale factor is a greater reduction in project costs for all projects with the differences getting proportionately greater the further one gets from the base case unit size. In essence using the 0.7 factor instead of 0.6, in this particular evaluation, will decrease costs for all units and will disproportionately decrease the cost of smaller units.

3. In using vendor budget quotes for SCRs, staff needs to add erection labor to the vendor quote. There is no indication that this is done in staff's analysis.

4. Staff does not condition the vendor's quotes to account for operational conditions, including unit upsets, and other project unknowns which will have direct bearing on SCR design details, performance and costs. An allowance must also be made for the accuracy inherent in vendor's budget quotations, which does not appear anywhere.

5. The PWVs provided for Refinery 7 and Refinery 9 are $27M and $19M respectively. There is an apparent inconsistency in these numbers as the stated capacity for each of these units is 55 kBPD. Units of the same capacity should have PWVs close to one another not differing by 42%. Staff should check these numbers and ensure that the SCR project scope differences between these two units can explain the large difference in cost.

Response 2-11

Again, staff appreciates and respect NEC's opinion with regards to our technical assessment of the FCCU costs. Staff notes areas of agreement and issues to be resolved.

1. Refinery 1 provided staff with comprehensive cost data for its FCCU SCR. As such, we used this model to estimate PWV and associated costs for other FCCUs where applicable. Your comments are correct in asserting the uniqueness of Refinery 1's situation, in particular the relative date of installation of an ESP to the FCCU. We realize that there are uncertainties in the cost estimate due to such considerations and have added a 50% contingency to our estimated costs. .

2. The PDSR based its scaling using a 0.7 factor established in practice and in the literature. The costs of $211 million estimated with the use of a 0.6 factor do not impact to the cost effectiveness calculation.

3. Staff concurs that the erection labor is a part of the installation costs included in the 4.5 factor

4. As previously stated, the PDSR cost estimates for the FCCUs included a 50% contingency factor to account for vendor cost estimation variability.

5. The PWVs for Refinery 7 and Refinery 9 were estimated using two different approaches. Refinery 7's PWV was estimated based on Refinery 1 actual cost data while Refinery 9's PWV was estimated based on the cost data submitted by the manufacturers. Originally, in 2013-2014 time frame, the manufacturers did not provide cost data for Refinery 7, 5 or 6 since these FCCUs already have SCRs or wet gas scrubbers. In Table F.5 of the PDSR, staff provided 2 different approaches to estimate the costs for Refinery 7 and Refinery 9. Using the manufacturer's cost data with 2 layers of catalysts and no markups, the PWVs for Refinery 7 and 9 would be $20 million. Using the manufacturer's cost data with 2 layers of catalysts and two levels of markups as recommended by NEC, the PWVs for Refinery 7 and 9 would be $31 million.

Comment Letter #3 – NORTON Engineering – September 4, 2015

General Comments

In its opening paragraph NEC is quoted "We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond."

NEC also commented on the general approach to creating cost curves to determine an effective cost curve to represent the PWV vs the maximum boiler/heater firing rate. Their analysis highlighted the paucity of SCR data and questioned the linear approach taken by staff. They commented that their power law curve better captured the relationship (within error bounds) when applied to specific Basin refinery SCR cases. They expressed that their cost curve better represented smaller heaters (<100mmbtu/hr heat release).

Response to General Comments

Staff recognized the issue and has directly quoted the NEC disclaimer from in the Non-Confidential Report in Appendix B of the DSR to help define the primary difference in the control equipment specifications proposed by staff and NEC.

With regard to the cost curve development and application, staff's analysis expanded beyond a solely SCR application to include control equipment including Great Southern Flameless Heaters, ClearSign Duplex technology for burners, as well as Electrodynamic Combustion Control technology. The staff analysis assessed the five sets of data to develop a set of representative PWVs to firing rates. Staff acknowledged in the DSR that cost curves developed by staff and NEC for higher firing rates converged and that the main difference was at firing rates less than 200 mmbtu. The differences between the cost curves generated by the varying control equipment design assumptions lead to the uncertainty reflected in the number of boilers and heaters deemed cost effective. The uncertainty as defined by the difference in emissions reduced 0.33 tpd for the category has been accounted for in the 0.85 tpd adjustment to the shave.

Comment 3-1 Scope of NEC's Review

NEC indicated that staff agreed with NEC that any dilution of NEC's effort to evaluate other alternative technologies than SCRs would not be desirable.

Response 3-1

Staff agrees that during an in-person conversation with Mr. Norton, the general understanding was for NEC to focus on SCRs as the primary control methodology. Regardless, staff sent to NEC information related to all control technologies discussed in Appendix A to Appendix E including technical studies, technical analyses, data that the refineries submitted as a result of the Survey, data that staff received from the manufacturers, facility drawings, facility permits, and manufacturers' contacts for NEC to review. In an email, staff also introduced NEC to all of the manufacturers that staff contacted.

Comment 3-2 Using FCC SCR Costs Increased Heater & Boiler SCR Cost Estimates

NEC explained the reasons that NEC elected to use FCCU SCR as the basis for its analysis for heater and boiler SCR. They cited uncertainty in vendor's response to their inquiries for additional data. They favorably compared a Basin refinery heater that achieved 1.6 ppmv to their FCCU SCR design and increase the costs to reflect installation of duct fan, new CEMS and ammonia storage tank.

Response 3-2

Staff agreed with NEC that the catalysts for FCCUs are not the same as the catalysts for boilers and heaters. Several prominent manufacturers indicated that a high dust application such as FCCU require a catalyst flow passage (or pitch) of about 7 mm. The refinery boiler and heater is a low dust application, and the catalyst pitch for this application is about 3 mm. The SCR for a refinery boiler and heater is generally compact and contains 1 layer of catalysts. The FCCU SCR contains 2 to 4 layers of catalysts, 2 or more filled with catalysts and 1 possible spare. The FCCU SCR has a large box area designed to fit additional equipment such as soot blower. Staff contends that NEC recommendation of 3 layers of catalysts for a FCCU SCR and 4 layers of catalysts for a boiler and heater SCR designed at 10 feet per second is different than a design provided by several prominent SCR manufacturers.

The SCAQMD facility permit database contains information on the catalyst volumes of the SCRs currently in operation in the District. The table below shows the catalyst volumes for several SCRs at the refineries, the rating for the boilers/heaters in mmbtu/hr, and the NOx emissions in ppmv that the refineries reported through the Survey. On average, the catalyst volume for the boiler and heater SCRs achieving 2 - 7 ppmv NOx is about 0.96 cubic feet of catalysts per mmbtu/hr based on the information in the facility permit database. The manufacturers indicated that the amount of catalysts needed to achieve 2 ppmv NOx is about 293 cubic feet for a 300 mmbtu/hr heater, and 92 cubic feet for 100 mmbtu/hr heater, or on average 0.96 cubic feet per mmbtu/hr. Staff estimated about 1.2 cubic feet per mmbtu/hr.

Table Z. 1 – Comparison of Information for Boiler and Heater SCR

Process Data	**NOx Emissions from Survey (ppmv)**	**Heaters/Boilers' Rating from Facility Permit Database (mmbtu/hr)**	**Catalyst Volume from Facility Permit Database (cubic feet)**
SCR for 4 catalytic reformer heaters	1.64	589	537
SCR for a hydrotreating heater	2.26	78	92
SCR for 3 coker heaters	2.71	528	623
SCR for a crude distillation heater	2.7	83	62
SCR for a hydrogen plant heater	2.7	653	691
SCR for 3 hydrotreating heaters	2.67	63	92
SCR for a crude heater	3.31	85	96
SCR for a crude heater	5	300	120
SCR for a boiler	5.39	245	225
SCR for 3 crude distillation heaters	5.69	849	810
Average catalyst volume using information from facility permit database (cubic feet per mmbtu/hr)			0.96
Catalyst volume provided by manufacturers for 2 ppmv SCRs (cubic feet per mmbtu/hr))			0.96
Catalyst volume estimated by Staff (cubic feet per mmbtu/hr)			1.2
Catalyst volume provided by NEC (cubic feet per mmbtu/hr)			17

Comment 3-3 NEC TIC Factor of 4.5 vs. Staff TIC Factor of 3.8

NEC explained the reasons that NEC elected to use a factor of 4.5 and the need to adjust vendor costs to include ancillary equipment such as ducting, fans, CEMS.

Response 3-3

Staff agreed with NEC and the refineries to use a factor of 4.5 and adjusted vendor costs to include ancillary equipment such as ducting, fans, CEMS. Staff revised the estimates prior to the release of the PDSR. The revised estimates resulted in slightly lower incremental emission reductions at a nominal increase in cost.

Comment 3-4 Basis for SCR Catalyst Increase and Velocity Reductions vs Vendor Budget Quotes

NEC indicated that staff analysis was based on only one SCR achieving 1.6 ppmv. This SCR has 1 layer of catalysts, however the heaters were fired at 65% capacity. NEC indicated that the vendor information provided by AQMD staff indicated that doubling a vendor catalyst volumes would be needed to ensure reliable operation in excess of five years, thus the minimum number of layers of catalysts needed would be 1 layer x 2 / 0.65 = 3 layers. NEC recommended 4 layers to ensure long term compliance while burning variable composition of refinery fuel gas. NEC also recommended 10 feet per second instead of 12 feet per second velocity as recommended by the manufacturers.

Response 3-4

Several prominent manufacturers indicated that one layer of catalysts is sufficient for a heater and boiler (or a gas turbine, or a SRU/TGTU incinerator) firing with refinery fuel gas. The SCR is typically designed at full rated capacity of the heater and boiler to sustain an operation between 3-year to 5-year turnaround period. The manufacturers indicated that even though the refinery fuel gas may contain some components (e.g. sulfur) that may poison the SCR catalysts, they have not yet seen a significant impact on catalyst poisoning in refinery fuel gas applications. The manufacturers indicated that a well-designed and maintained SCR system with good ammonia distribution system can meet 2 ppmv NOx.

Comment 3-5 Cost of New CEMS vs Upgrade and Ammonia Tank

NEC indicated that they did not have any data on the status/condition of existing CEMS. NEC proposed the cost of a new CEMS at an approximate cost of $1 million. NEC indicated that they used ~~used~~ a common 11,000 gallons ammonia tank for all sizes of heaters and boilers in their proposals.

Response 3-5

The cost of $1 million for CEMS is not consistent with the information submitted in CEMS applications. Staff understand the reason for a common 11,000 gallons ammonia tank and included the costs for ammonia tanks as recommended by NEC in the revised estimates prior to the release of the PDSR. This adjustment results in nominal change in costs.

Comment 3-6 High Catalyst Replacement Costs Skewed NEC PWVs High

NEC indicated that NEC agreed with staff that replacement costs of the 4-layer SCR catalyst system would skew NEC PWV higher and NEC corrected their estimates.

Response 3-6

Staff concurs.

Comment 3-7 NEC's estimates are higher than staff's "conservative" PWVs

The SCR listed in PDSR Table G.8 is shared between four heaters. The combined total rated capacity of the four heaters is 589 mmbtu/hr. NEC indicated that staff should have used $43.2 million as an estimate for a shared SCR of a 589 mmbtu/hr heater compared with $38.5 million to the total costs of the four individual SCRs that staff estimated. NEC estimated that 4 individual SCR units installed to meet the 589 mmbtu rating would require $99 M.

Response 3-7

Staff agrees that the common stack-shared SCR application is more appropriate and less costly that individual units being installed. NEC also noted that the difference in costs estimated by staff and their engineers was less than 12 percent.

Comment Letter #4 - RECLAIM Industry Coalition, August 21, 2015

Comment 4-1 Shave amount and timing

A shave of 4 tons per day in 2016 does not allow any time for facilities to develop and implement emission reduction measures. The Coalition believes that the shave amount for the period 2016-2017 should be no more than 2 tons per day, and that there is no reason that all two tons have to be shaved in 2016.

Response 4-1

With respect to the implementation time, because the implementation date for 2 tpd reductions in Control Measure CMB-01 Phase 1 was past due in 2014 and there are 5-8 tpd surplus RTCs in the market, staff believes that at a minimum 2 tpd reduction or up to 4 tpd reduction should be removed from the market no later than 2016-2017. Staff disagrees that this proposal does not allow adequate time for implementation because there are sufficient unused RTCs in the market to allow a 4 ton shave in 2016-2017 without requiring controls to be installed in those years. The removal of unused RTCs would raise the RTC prices and stimulate the implementation of control equipment. It is urgent to implement the control equipment and reduce actual emissions as expeditiously as possible to meet the NAAQS for PM2.5 and ozone.

Comment 4-2 Shave amount and timing

There is no commitment in the AQMP to make a 4-ton per day shave in 2016. The AQMP contemplated a 2-3 ton per day reduction in Phase I and another 1-2 tons per day in Phase II. With respect to the total amount of the shave, the Coalition continues to believe that shaving a total of 14 tons per day of RTCs from the RECLAIM market in order to achieve the 8.79 tons per day reductions the District seeks to obtain as a BARCT adjustment is neither necessary nor justified

Response 4-2
Please see Response 1-2.

Comment 4-3 Cost effectiveness

The Coalition continues to believe that a 25 year useful life assumption (used consistently for all equipment in this proposed rulemaking) is not appropriate for all equipment.

Response 4-3
Please see Response 1-4.

Comment 4-4 Cost effectiveness

District staff minimizes control costs by using a cost-effectiveness calculation that is not used by the California Air Resources Board and most other major California air districts (i.e. LCF Method). Additionally, the use of a $50,000 per ton figure (i.e. based on DCF method) as the cost threshold is more than twice the $22,500 per ton threshold (i.e. based on LCF method) applied to command-and-control regulated sources.

Response 4-4
Please see Response 1-9.

Comment 4-5 Cost effectiveness

We also note that Norton Engineering (the third party independent contractor retained by the District to review and assess the District staff's cost effectiveness determinations) has raised questions regarding the District staff's cost effectiveness determinations and its dismissal of Norton Engineering's analyses when those analyses showed higher costs than the District staff's evaluation showed.

Response 4-5
Please see Responses 1-6.

Comment 4-6 Need for the "gap"

Our analysis has shown that even if the District staff concluded that NO BARCT improvements had been made between 2005 and today, the staff's methodology would result in 6 tons per day of NOx RTCs being removed from the program. RTCs being removed under the District's methodology would include those needed for 1) NSR Holding Requirements, 2) Electric Grid Reliability and Implementation of AQMP Attainment Strategies (i.e., large scale electrification to replace current combustion processes), 3) Post-2023 Growth, 4) Investor Holdings, 5) Shutdowns and 6) ERC Conversions. The Regional NSR Holding Account is to be used for both NSR Holdings and to cover actual emissions in certain cases which raises the question of whether it is large enough. The shave of 14 tpd is too large and runs the risk of repeating the program "meltdown" of 2000-2001 during the power crisis when insufficient RTCs were available.

Response 4-6

Staff agrees with the commenter that using the staff's methodology (Figure EX-1), if there were no new 2015 BARCT, the RTC shave would be:

Allocations – (2011 emissions at 2005 BARCT x 1.1 for 10% compliance margin) = 26.5 – (1.1 x 18.3) = 6.4 tpd

This shows that the 2005 shave was not large enough to remove the unused RTCs (or the "gap") to the level that can stimulate the installation of actual control devices. Thus, in the past 10 years since 2005, there was only 4 SCRs installed at the refineries even though staff had estimated that it was feasible and cost effective for the refineries to install 51 SCRs by 2011.

Staff methodology in estimating the remaining emissions in 2023 does include the impact of growth to 2023 and the possibility of returning operation for shutdown facilities and new electric generating facilities. Staff may need to revisit the NOx RECLAIM post 2023 to incorporate advancement in control technology, but it is not appropriate to include post-2023 growth in the 2023 target as this will result in an artificially high target. Staff also creates a separate Regional NSR Holding Account to address the NSR holding requirements for new power producing facilities and is in the process of discussing with EPA to seek its approval. Moreover, the NSR Holding requirement and the use for power emergencies are not additive. Since the facility NSR Holding requirement is its maximum potential to emit, actual emissions will always be smaller and will be covered by the same RTCs used for the NSR Holding requirement. Investor holdings and ERC conversions are subject to shave consistent with the previous 2005 and 2010 RECLAIM amendments. Staff has accounted for electric reliability by allowing "nontradable/nonusable" RTCs to become usable by power producers if a grid reliability emergency is declared. Staff has accounted for increase electrification through the growth factor which assumes increased use of renewables. Note that ERCs of non-RECLAIM facilities do not hold their values to eternity, they are often recalled and reduced per Regulation XIII. Rule 2002 (f)(1) contains a safety valve to provide a stability for the RECLAIM market and ensure that when RTCs are not sufficiently available (i.e. the 12-month rolling average RTC price exceeds $~~15,000~~22,500 per ton), staff can convert the non-tradable/non-usable RTCs to tradable/usable RTCs upon the concurrence of the Governing Board.

Comment 4-7 Energy efficiency projects

The Coalition strongly opposes any effort to further reduce RTC allocations due to "energy efficiency projects" that have or would reduce NOx emissions. Any reduction in NOx emissions not strictly required by BARCT should be encouraged and the benefits of making those reductions retained by the facility operator making them.

Response 4-7

Staff did not consider further reduce RTC allocations due to energy efficiency projects at this time. However, it should be noted that the energy efficiency projects resulted in 0.7 tpd concurrent reductions of NOx completed in 2011, and the RTC allocations adjusted in 2005 have not yet been reduced to account for these reductions.

Comment Letter #5 – Latham & Watkins, August 20, 2015

Comment 5-1 March 20, 2015 freeze date for shave estimation

The first time Harbor Cogeneration Company (HCC) was made aware of the freeze date of March 20, 2015 for shave estimation was just prior to the public workshop on July 22, 2015. However, staff proposal to establish a retroactive baseline date without prior advance notice constitutes an unprecedented ex post facto action that unfairly disadvantages entities that have made good faith trades after March 20. Two examples were provided and the commenter suggested the District propose the date of rule amendment as the freeze date for shave estimation.

Response 5-1

Staff has revised the proposal and notified the stakeholders regarding the proposed new freeze date of September 22, 2015. Staff cannot practically make the freeze date for shave estimation the date of rule amendment because the rule language and calculation of shave must be completed for public review and comment prior to the Governing Board hearing for rule adoption. Staff disagrees that setting the freeze date prior to rule adoption is an "ex post facto" regulation. The prohibition on "ex post facto" laws or regulations applies to making conduct criminal that was not criminal when it occurred, or increasing the criminal penalty [in re Lomax, 66 Cal. App 4th 639 (1998)]. In contrast, ordinary civil law may be made retroactive, but it must be expressly so stated in the language, or state statute, or clear form extrinsic evidence [Myers v Philip Morris Companies, Inc., 28 Cal 4th 828 (2002)].

Comment Letter #6 – Yorke Engineering, LLC., August 21, 2015

Comment 6-1 New Emission Factors for Rule 219 Exempt Equipment

We support the District's August 19th proposal for new provisions in Rule 2012 Chapter 4 to allow equipment certified by either U.S. EPA, CARB, or SCAQMD to use an emission factor other than the default factor of 130 lb/mmscf to report NOx emissions.

Response 6-1

An August 19th presentation by staff acknowledged the issue and mentioned a possible path forward relying on source tests rather than the default factor. Based on feedback form stakeholders, the concept did not seem to achieve the goals of the request, and thus, staff is not proposing an alternative to the default factors at this time.

Comment 6-2 Source Test for Rule 219 Equipment

The District's August 19th proposal for certified Rule 219 exempt equipment indicates source tests may be required to verify lower emissions. We request that no source test shall be required for certified equipment.

Response 6-2

Source testing is the preferred method of verifying the certified emissions for these units. The RECLAIM program offers the flexibility of a market program, but also has stricter standards for emission reporting than many command and control regulations. Based on feedback from stakeholders, the concept did not seem to achieve the goals of the request, and thus, staff is not proposing an alternative to the default factors at this time.

Comment 6-3 RTU Reporting

The current requirements are specified in 2012 Appendix A, Chapter 7 – Remote Terminal Unit (RTU) Electronic Reporting. This section of the rule requires facilities to use dial-up modem technology to transmit a text string that must be very specifically formatted. We have wasted hours of time working with this antiquated system which is still required by the regulation. We urgently request that the District update their electronic reporting system to allow more modern and easy to use technology.

Response 6-3

We agree that the electronic reporting system needs to be updated. This upgrade, however, would be very resource intensive for SCAQMD staff and the affected operators and is outside the scope of this rule making. The RTU electronic reporting system will be upgraded and the corresponding rulemaking will occur at that time.

Letter # 7 - Charles F. Timms, Jr. August 21, 2015

Comment 7-1 Electric Generating Facilities Need Quicker Access to Non-tradable/Non-usable RTCs

Based on the experience of power plants during the energy crisis of 2000-2001, this cumbersome, two-step process for releasing these RTCs to cover annual emissions appears to be too slow to avoid skyrocketing spot prices or an outright shortage of RTCs for power plants to either cover annual emissions or demonstrate resource adequacy. We understand that the Los Angeles Department of Water and Power will be presenting a more detailed description of how the two-step process for releasing RTCs during the energy crisis of 2000-2001 did not avoid high prices and shortages of RTCs at that time.

The Cities therefore suggest that a provision be added allowing power plants to request that some or all of this pool of non-tradable, non-usable RTCs be converted to usable but non-tradable RTCs, in exchange for a fee of $7.50 per pound. Once converted, the RTCs could be used to cover annual emissions or meet resource adequacy needs for the year in which the request is made, but they could not be traded. In addition, the power plant also would not be allowed to trade any of its own RTC allocation for the year in which the request to convert is made.

The fee serves two purposes. First, it gives power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound. As long as the spot price of RTCs remains below that level, power plants will not have an economic incentive to make a request to convert. Instead, they will rely on the RTC market to acquire additional needed RTCs. But if the spot price rises above $7.50 per pound, then they will have an incentive to make a request, if they deem it prudent to do so. Of course, power plants would be free to wait for the slower two-step process to unfold regarding the 12-month rolling average price, and obtain additional unrestricted RTCs without a fee, if they deem that to be the more prudent course.

The fee also serves the purpose of providing the District with funds to achieve additional NOx reductions from other sources, including mobile sources, for which cost-effective reductions cannot otherwise be obtained.

Response 7-1

SCAQMD staff has taken your comments into consideration and has proposed a mechanism for accessing non-tradable/non-usable credits and also credits in the Regional NSR Holding Account with associated triggers. For the first year of the shave, the entire non-tradable/non-usable portion of a facility may be accessed if the rolling 12-month RTC price exceeds $~~15,000~~22,500/ton. Those credits would become usable and tradable. The non-tradable/non-usable credits would also be accessed if the Governor of California declares a State of Emergency, but would be usable/non-tradable. Staff is not proposing a fee for access to the Regional NSR Holding Account due to comments received at Working Group and other meetings from many other electric generating facilities that a fee should not be imposed for using these credits.

The commenter also expresses that the non-tradable/non-usable RTCs not be removed from the facility permits after the end of the shave as these credits will be greatly needed then. Staff has established the Regional NSR Holding Account such that the non-tradable credits for newer ~~electrical~~ electricity generation facilities that would normally go to the SIP after one year for each year of the shave would now go in the Regional account every year of the shave beginning in 2017. So when the shave is complete, the shaved portion would be available to meet NSR purposes for these facilities and also provide relief in the event of a power crisis. A regional hold account offers more flexibility than if each facility held the amount reduced for their facility. For example, if there is a power emergency, not every facility will need to run. One or more facilities may be non-operational, and it is conceivable that not all facilities will be called on to the same extent to operate during an emergency.

Comment 7-2

As mentioned earlier, the staff proposal contains an "Adjustment Account" enabling post-1993 power plants to meet the NSR holding requirement on a programmatic basis. We understand that staff estimates that 1 to 1 ½ tons of RTCs will be needed for this account [see Draft Staff Report at p. 33]. We suggest that the RTCs in this account also be made available to affected facilities to cover their annual emissions, in exchange for a fee of $7.50 per pound. There does not appear to be any impediment to allowing the RTCs involved to serve both purposes.

As in the case of a request to convert non-tradable, non-usable RTCs to usable but non-tradable RTCs, the fee serves the dual purpose of giving power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound, and also providing the District with funds to achieve additional NOx reductions from other sources for which cost-effective reductions cannot otherwise be obtained.

This use of the "Adjustment Account" could be viewed as an alternative to the suggested provision regarding the non-tradable, non-usable RTCs discussed above.

Attachment 2 to this letter contains an example of rule language that might be used to allow RTCs in the "Adjustment Account" to both meet the NSR holding requirement and be available to cover annual emissions.

Response 7-2

As stated in the previous response, access to the Regional NSR Holding Account would be for credits that could cover NSR holding requirements for newer ~~electrical~~ electricity generating facilities, as well as covering annual emissions for all ~~electrical~~ electricity generating facilities in the event of a power crisis.

Comment 7-3

Two suggestions on the provisions related to the RATA testing:

> First, the due date for performing the RATA should be 30 days, rather than 14 days, from the re-firing of the major source. The additional time is needed in some circumstances to perform tests on the source to ensure reliable and safe operation. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]
>
> Second, the proposed requirement to disconnect and flange the fuel feed lines is unnecessary and costly. The proposed requirement is unnecessary because the fuel meters are required to be maintained, associated fuel records are required to be kept, and stack emissions are continuously monitored and recorded. So there are multiple sources of data to rely on to verify that the source is not operating. The proposed requirement is costly and time consuming because significant manpower and equipment would be needed to meet it. There also may be health and safety risks if asbestos-containing materials are encountered in the work. The Cities therefore suggest that this requirement be deleted. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

Response 7-3

Staff believes that the due date of 14 operating days from re-firing of a major source is sufficient for performing a RATA. The operating days do not have to be consecutive days so the total calendar days since the re-firing could be longer.

The proposed amendment for requiring the disconnection and flanging of fuel feed lines to demonstrate non-operation is necessary because this is the only reliable way to ensure that SCAQMD compliance staff can visibly confirm non-operation and no fuel flow. This prevents possible circumvention for other existing methods of demonstrating non-operation such as stack emission monitoring and recordkeeping.

Comment 7-4

a. **Provisions Involving the Non-tradable, Non-usable Adjustment Factor**

i. The staff proposal should be clarified to provide that the 12-month rolling average RTC price that may trigger release of the non-tradable, non-usable RTCs is the "weighted" average. [PAR 2002(f)(1)(E)]

ii. The staff proposal speaks of determining the 12-month rolling average RTC price for all trades in the "current compliance year." It is not clear how this language would apply to a 12-month rolling average price when the 12 months in question straddle two adjacent compliance years. [PAR 2002(f)(1)(E)]

iii. In PAR 2002(f)(1)(F), the correct cross-reference appears to be to PAR 2002(f)(1)(E), not PAR 2002(f)(1)(F).

Response 7-4

The comment discusses the provisions regarding the non-tradable, non-usable adjustment factors. The commenter states that 12-month rolling average should be a weighted average. Staff calculates the rolling 12-month average by totaling the dollar sum of all the sales and dividing by the total sum of all the pounds (or tons). This price is reported monthly to the stationary source committee. The commenter also questions how the 12-month rolling average is determined for all trades in the current compliance year when there are two cycles that overlap. Staff calculates the 12-month rolling average for all trades including cross-cycle transactions, but not including RTC transactions reported at no price or RTC swap transactions. The commenter also pointed out a rule reference error in PAR 2002 (f)(1)(F). Staff has corrected the reference.

Comment 7-5

b. **Provisions Involving the "Adjustment Account"**

i. The staff proposal includes a provision allowing access to "Adjustment Account" RTCs for the purpose of compliance with annual emissions during a State of Emergency as declared by the Governor. [see PAR 2002(f)(5)] This provision raises several questions:

(1) How is the account to be funded for this purpose, and with what quantity of RTCs? As we indicated earlier, we understand that staff estimates that 1 to 1 ½

tons will be needed to meet the NSR holding requirement. Will additional amounts be added to fund the account to allow compliance with annual emissions?

(2) Why is access to RTCs limited to a State of Emergency declared by the Governor, as opposed to a State of Emergency declared by a local government official, such as a Mayor?

(3) We understand that in response to questions raised at the Working Group meeting on August 19, District staff indicated that RTCs in this account can be used both to meet the NSR holding requirement and to cover annual emissions. If our understanding is correct, then the rule language needs to be clarified.

(4) It may not be appropriate for the Executive Officer to have unfettered discretion to determine the amount and distribution of RTCs. By making these determinations, he would in effect decide which power plants generate electricity during a State of Emergency. Such decisions may be beyond his authority and expertise. It is important, moreover, that every power plant have access to the RTCs it needs to meet its operating requirements.

Response 7-5

The comment discusses the provisions involving the Regional NSR Holding Account (previously called the Regional NSR Holding Account). The commenter asks how the account will be funded and whether additional funds will be needed to allow compliance with annual emissions. The Regional NSR Account will be funded up to the amount that is shaved from those electric generating facilities that have multi-year NSR holding requirements each year of the shave. As stated in Response 7-1, for the first year of the shave the entire non-tradable/non-usable portion of a facility may be accessed if the rolling 12-month RTC price exceeds $~~15,000~~22,500/ton. Those credits would become usable and tradable. The non-tradable/non-usable credits would also be available for offsetting emissions if the Governor of California declares a State of Emergency related to power generation or grid stability, but would be usable/non-tradable. For NSR holding purposes, newer ~~electrical~~ electricity generation facilities can access both their non-tradable/non-usable RTCs and the Regional NSR Holding Account RTCs.

The commenter also asks why the State of Emergency declaration can only be made by the Governor and not by a local government official. Staff believes that a major power crisis would warrant this type of declaration and not just an elevation in power demand. Staff understands that there are other factors to consider, such as the increase in the electrification in the transportation sector that may cause the demand to rise. Combined with the lesser amount of RTCs available as a result of the shave and higher resultant RTC prices, power-producing facilities may need some relief to gain access to more RTCs. Staff feels that the safety valves in the proposed amendment would address these concerns. Nonetheless, staff proposes to add resolution language to monitor the power-producing sector for trends in power consumption and associated NOx emissions as electricity demand potentially increases.

The commenter also states that the rule language needs to be clarified to detail that the Regional NSR Holding Account would accommodate NSR requirements and annual emissions in the event of a power crisis. Staff has made these clarifications in the rule language and staff report.

The commenter lastly states that it may not be appropriate for the Executive Officer to determine the amount and distribution of RTCs and thereby make the determination of which electric generating facilities would generate electricity during a State of Emergency. Each individual electric generating facility subject to the shave would also have access to its non-tradable/non-usable account if the 12-month rolling average RTC price threshold trigger is reached, or if a State of Emergency is declared. The credits in the Regional NSR Holding Account would also be made available to all electric generating facilities under a State of Emergency. If the State of Emergency is prolonged, the proposed amendments now provide for a report to the Governing Board after any power crisis trigger such that a plan for distribution of RTCs and possible program adjustments can be made before the supply of emergency RTCs is exhausted.

Comment Letter # 8 – SCEC Dated August 26, 2015

Comment 8-1

Responsiveness of Mitigating Actions. The Cities are concerned that rolling average RTC price may trail too far behind sudden RTC price increases and the requirement to obtain Governing Board authorization to convert the holdings to tradable and useable credits may not be suitably responsive to our needs as municipal utilities. In other words, the Cities' need for certainty and swift access to RTCs may be jeopardized and we will be forced to participate in a market with escalating costs and limited RTC availability until the point that the $15,000 threshold is reached. By the time the SCAQMD responses are implemented, it will be too late to undo the damage to the utilities and local communities.

Response 8-1

The comment states that if access to additional credits can be realized in a faster timeframe for unforeseen situations where emergency power generation may be necessary. The staff proposal has safety valves through which additional credits can be accessed, including the immediate access in the event of a power crisis. We understand that there may be some situations where the need to additional credits may arise more rapidly than, for example, a gradual upward trend in power generation. A facility would still have time to reconcile emissions at the end of a compliance quarter and compliance year, which include a reconciliation period.

Comment 8-2

Request for Flexibility in Accessing Non-~~tradeable~~tradable / Non-useable Holdings. The Cities are supportive of the proposals to expand access to credits (at either no costs or $7.50 per pound which is equivalent to $15,000 per ton) and believe that they would be beneficial to the utilities and the RECLAIM program in general. By providing access to these credits in advance of a market upset, the District would provide municipal utilities the certainty needed to meet our mission at a reasonable cost and the limited access of utilities to their non-tradable credits may actually prevent market upsets that would trigger the widespread release of non-tradable/non-useable credits to all RECLAIM operators. Finally, if utilities are assessed a fee for their use of the non-tradable/non-usable credits in advance of the 12-month price trigger being reached, the proceeds would be available to the District to facilitate voluntary NOx emission reductions

Response 8-2

The comment expresses support for the accessibility to non-tradable credits in the event of a market upset. SCAQMD staff has provided safety valves to provide access to the non-tradable/non-usable account and to the Regional NSR Holding Account in the event of the 12-month rolling average threshold price trigger being reached or in a State of Emergency. Other stakeholders do not believe there should be a cost to access such credits. Please see response 7-1.

Comment 8-3

Sunset of Non-tradable/Non-usable Holdings. The Cities understand that SCAQMD proposes to discontinue the non-tradable/non-useable holdings in the year 2022. Given the uncertainty presented by increased integration of renewable resources and regional electrification, the Cities ask SCAQMD to provide for continued utilization of the non-tradable / non-useable holdings, at least for municipal utilities.

Response 8-3

The comment requests that the non-tradable/non-usable holdings to be provided in perpetuity to municipal utilities. The staff proposal intends to submit the non-tradable portion of the shave into the SIP, and if they were held indefinitely and could potentially be accessed, they would never be available for SIP emission reductions. However, for new electric generating facilities subject to multi-year NSR holding requirements, the shaved portions of holdings will go into the Regional NSR Holding Account. This account will hold the RTCs for NSR purposes in perpetuity and will provide relief to these facilities, while setting aside some RTCs for future uncertainty in the electricity market. Staff intends to include a resolution to closely monitor the impacts of potentially increased electricity demand and renewable penetration on NOX emissions, and will propose RECLAIM program adjustments to the Governing Board if needed.

Comment 8-4

Regional NSR Holding Account, Compatibility of Dual Purposes. The Cities appreciate that SCAQMD is proposing alternatives that would ease the NSR holding requirement burden and also provide additional RTCs in the event of an emergency. However, it is not clear that both purposes can be simultaneously served, given the amount of RTCs that SCAQMD proposed to allocate to the account. The Cities ask that SCAQMD clarify how the account can be available for emergency use by all ~~electrical~~ electricity generating facilities, without jeopardizing the ability of new facilities to make the NSR holding demonstration.

Response 8-4:

The commenter has concerns with how the Regional NSR Holding Account will be able to support the NSR requirements for facilities if the account is accessed by all electric generating facilities in a State of Emergency. The proposed rule language clarifies how the NSR Regional Holding Account would be implemented, and that it would be available to all ~~electrical~~ electricity generating facilities under a State of Emergency. There is no issue with using such RTCs for dual purposes. The NSR holding requirements cease after the compliance period ends, and if they are not used to offset actual emissions, the credits become available for other purposes. This is the situation as it exists today as RTCs can be sold after the compliance period ends.

Comment 8-5

Additional entities or authorities should be allowed to declare the presence of an energy emergency at both a regional and local level. Many emergencies requiring local power generation may exist within the boundaries of a city and state or regional authorities may not be able to investigate and make the necessary declaration quickly. Local authorities, such as a City Manager or Mayor, should also be allowed to make a declaration that would allow for the release of RTCs from the Regional NSR Holding Account.

Response 8-5

The commenter asks why the State of Emergency declaration can only be made by the Governor and not by a local government official. Staff believes that a major power crisis would warrant this type of declaration and that local emergencies can be handled within the framework of the RECLAIM program, such as purchasing credits in the market to reconcile these emissions. If there is a necessity for credits, such an exceedance of the 12-month rolling average RTC price threshold trigger, then the non-tradable credits could be made available. See Response 7-5.

Comment 8-6

It is unclear how access to RTCs would be granted or how competing applicants would be prioritized by SCAQMD to receive RTCs. SCAQMD must further define its role in the process of granting access to the Regional NSR Holding Account if the Cities are to be assured that credits are available not only for the NSR holding demonstration, but also for easy access in case of an emergency.

Response 8-6

The comment requests for further definition as to how the Regional NSR Account credits will be prioritized for distribution. If the Governor declares a power emergency, the current year non-tradable/non-usable RTCs held by electric generating facilities can be used to offset emissions after exhausting their own usable RTCs, unless they sold any part of their RTC holdings for the subject compliance year. If an eligible facility has exhausted their non-tradable/non-usable RTCs, it may apply for use of the accumulated RTCs in the Regional NSR account. The supply of emergency annual RTCs will be sufficient to handle a short term crisis. If the crisis is prolonged such that the demand for emergency RTCs is greater than the supply, there will be time to return to the Governing Board to make program adjustments. The staff proposal includes provisions to report to the Governing Board and proposes a plan for RTC distribution and other program adjustments when the State of Emergency access is triggered.

Comment 8-7

The Cities ask SCAQMD to clarify how the Regional NSR Holding Account would affect the way in which new power producing facilities would manage the remaining RTCs listed in their facility permits, with respect to the Rule 2005 (f) holding requirement. Ideally, provisions to accommodate the holding requirement would also allow facility operators to sell the remaining unused RTCs listed in their permit in advance of compliance year closure. We also ask SCAQMD to give consideration to the same discretionary use of the Regional NSR Holding Account by municipal utilities that is proposed within this letter for the non-tradable/non-useable holdings.

Response 8-7

The comment requests for further clarity on how the Regional NSR Account will affect how the RTCs are reflected on the facility permits. Amounts of NSR holdings going into the Regional account year by year is listed in Rule 2002 for each facility. On the facility RECLAIM permits, Section B would still contain the usable/tradable and non-usable/non-tradable amounts, but the permit condition will refer to Rule 2002.

The commenter also request the same use of the credits from the Regional NSR account to the non-tradable/non-usable holdings. For newer electric generating facilities, the non-tradable/non-usable holdings and the holdings in the Regional account are essentially drawn from the same pool of credits. For every portion of the shave designated as non-tradable/non-usable, the RTCs will go into the Regional account the following year, instead of being submitted into the SIP. Facilities would have access to the Regional account portion for offsetting annual emissions if a State of Emergency is declared. The non-tradable credit portion for newer facilities would not be available for sale, however.

Comment Letter # 9 – Eco Services Letter Dated August 28, 2015

Comment 9-1

Eco Services does not support a program that leaves no reasonable means of complying. We support revisions to the RECLAIM program that rely on implementation of feasible and cost-effective controls. Sources that can implement BARCT can and should do so as a first step towards additional reductions. We strongly urge the SCAQMD to consider this approach which will result in a reduction of NOx emissions based on cost-effective controls which will not cripple the RECLAIM trading program and leave smaller emitters no real cost-effective option for compliance. If the SCAQMD pursues the across the board shave, it will effectively be imposing cost-effective requirements on the BARCT sources but not considering cost-effectiveness at all for non-BARCT sources. Eco Services believes that is inequitable and inappropriate.

If the SCAQMD does pursue an across the board NOx shave, Eco Services recommends that the changes to RECLAIM include some type of measure to limit the costs of NOx credits in addition to the current $15,000 per ton annualized average cost, particularly for small emitters. An equitable rule should provide the regulated community with a cost-effective means of complying. We request that the SCAQMD somehow provide a ceiling on the financial impact it will have on RECLAIM participants in terms of cost-effectiveness. BARCT sources will be subjected to cost-effective controls. Similarly, the financial impact to non-BARCT sources should also be based on cost-effectiveness.

It is our understanding that Non-Tradable/Non-Useable allocations will be issued to emitters, and that these “safety valve” allocations can be used as compliance instrument when the average cost of annual NOx RTC exceeds $15,000 per ton (or $7.50 per pound). However, we believe that the time for cost averaging should be significantly shortened to prevent the repeat of situation similar to year 2000 when the value of annual NOx RTC went far above the $7.50 per pound threshold. Also, additional safe guards should be considered to prevent non-compliance for non-BARCT sources if the NOx RECLAIM market fails such that no NOx RTCs are available to be purchased.

Response 9-1

The comment expresses concerns about the effect of the shave on a facility, such as Eco Services that does not have equipment subject to BARCT. Staff appreciates your comment and acknowledge all your efforts in reducing SOx emissions with the installation of the wet gas scrubber at your facility. We believe that if BARCT reductions are achieved in 2022, there should still be a comparable margin in the market between the allocation cap and the actual emissions as there is today. The current market has about a 28% margin, while in 2022 the market should have about a 23% margin if BARCT controls are installed. The implementation schedule is over several years, so the full magnitude of the shave would occur gradually. As the allocation cap decreases, the price of RTC is expected to rise. Despite this, there is a safety valve that would allow for more RTCs to be accessed in the event that the 12-month rolling average threshold price trigger is reached. The commenter also has concerns of the financial impact to facilities facing a similar situation. Please refer to the socioeconomic report. The commenter also makes reference to a prior comment letter submitted on April 27, 2015 which refers to the price of purchasing credits based on the current market value. We acknowledge that at the current price of credits of around $100 per pound, the cost of purchasing credits after the shave to offset annual emissions would be in the neighborhood of $2.6 million for your facility. Your facility is included as part of the shave because it is among the top 90% of RTC holders and the RECLAIM program will have some structural buyers.

Comment Letter #10 – Charles Timms, Jr. Letter Dated September 17, 2015

Comment 10 - 1

We have identified some additional rule language that would need to be amended to facilitate our proposal that power plants be provided with quicker access to non-tradable/non-usable NOx RTCs, and/or access to RTCs in the Adjustment Account, if needed to cover annual emissions. This additional language will ensure that the relevant RTCs are only credited to the SIP on a year-by-year basis to the extent they are not needed for power plant compliance purposes. See Attachment 1 to this letter.

In addition, the Cities support the proposal of the Los Angeles Department of Water and Power to expand the emergency provisions in the staff proposal to allow power plants to access RTCs in the Adjustment Account if an energy emergency alert is declared by the relevant electrical "Reliability Coordinator." See Attachment 2 for proposed rule language.

Proposed Amended Rule 2002(f)(1)(J) shall be amended to read as follows:

"The NOx RTC adjustment factors for compliance years 20019 through 2021 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022 NOx RTC adjustment factors shall not be submitted for inclusion in the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year. At the end of each compliance year reconciliation period from 2022 and each year thereafter, the Power Producing Facility shall surrender unused non-tradable RTCs to the District for inclusion into the State Implementation Plan."

Proposed Amended Rule 2002(f)(5) shall be amended to read as follows:

"During a State of Emergency as declared by the Governor or an Energy Emergency Alert as declared by the Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the ~~Executive Officer~~ Power Producing Facilities based on the ~~impact that~~ amount of energy they produce during the State of Emergency ~~has on the RECLAIM program~~ or the Energy Emergency Alert."

'Reliability Coordinator' means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

Response 10-1

The commenter has suggested that additional rule language be added to ensure that unused RTCs for emissions compliance from electric generating facilities are submitted into the SIP on a year-by-year basis. The proposed rule language establishes the mechanism by which the non-tradable and Regional NSR accounts are handled. The non-tradable account is the yearly shaved amount of RTCs. The rule language states that after one full compliance year the credits will be submitted into the SIP. For the first year of the shave, the non-tradable account can be accessed if the 12-month rolling average threshold price trigger is reached or if there is a State of Emergency. For electric generating facilities with continual NSR requirements, the non-tradable balance can be used for NSR holding purposes, and subsequently will become the portion that will fund the Regional NSR account for the same purpose. However, the RTCs may be used for compliance with annual emissions and will become usable if the price trigger is reached or a State of Emergency is declared. Existing electric generating facilities will also have access to their non-tradable/non-usable RTCs in a State of Emergency, as well as the Regional NSR Holding Account. If the non-tradable account is accessed, the following year's permit will be adjusted accordingly.

The commenter also provided some suggested rule language that echoes the same comments from the previous comment letter regarding the designation of a State of Emergency by someone other than the Governor. As stated in the response to comment 7-5, the safety valves that are proposed by staff are sufficient to ensure that there will be available credits in the event of either a shortage of credits or a major power crisis as declared by the Governor. Staff does not support allowing the Reliability Coordinator to dictate access to the Regional NSR account because an "alert" is not a true State of Emergency requiring extraordinary measures.

Comment Letter #11 – Southern California Edison No Date

Comment 11-1

The shave should drive sources towards BARCT

The shave, as proposed, would constitute a 53% reduction in the total number of RTCs in the market. 67% would be taken from the refinery sector while 47% would be taken from the non-refinery sector, including electric generation facilities. While this would be better than an outright across-the-board shave, it still would trigger costs for the electric generation sector that would have no commensurate impact on reducing air emissions. The electric generation facilities are already at Best Available Control Technology (BACT) with no existing opportunity to reduce emissions (other than curtailing operation, which is not feasible for electric generation facilities since electric demand will dictate operating times). While there is recognition there will have to be some reduction of RTCs from electric generation facilities, the shave should cause facilities not currently at BARCT to install better controls. With the proposed percentages, the costs will disproportionally impact facilities that are already at BACT and result in a subsidization by those at BACT of facilities not yet utilizing the best controls.

Response 11-1

The commenter states that there will be cost impacts to electricity generating facilities when there is no reduction in emissions from these sources. While we recognize that most of the equipment used by the electric generation sector is at BARCT or BACT, the proposed shave affects the top 90% of RTC holders and is necessary to obtain the highest amount of feasible reductions to meet SCAQMD's attainment goals. Note that most electricity generating facilities hold a significantly more RTCs than their actual emissions, and that staff is proposing resolution language to monitor trends in electricity demand and propose program adjustments if necessary. The staff proposal has several safety valves that can address certain issues that are specific to the ~~electrical~~ electricity generating sector, such as relief from yearly NSR holding requirements.

Comment 11-2

The proposed shave amount on the Electric Generation Facilities in effect caps the amount of fuel we can use

As stated above, SCE's electric generation facilities are already at BACT or BARCT, with no currently feasible opportunity, from a control standpoint, to reduce emissions further. With no advancements in control technology, the only way to further reduce emissions is by curtailing operation (i.e. limiting fuel usage). Thus, if no credits were available for purchase on the open market, which is a possibility given the proposed size of the shave, the only way to stay in compliance would be by reducing fuel usage.

It should also be noted that under the California Health & Safety Code for market-based programs [§39616(c)], a program must not result in disproportionate impacts to stationary sources in the program as compared to other permitted stationary sources not in the program. A typical permitted source not in the RECLAIM program is subject to rule-based command and control regulations. Were SCE's facilities not in the RECLAIM program, command and control regulations would require BACT concentration limits with no further limits on operation or fuel use, unless such further limits were agreed to for PTE or CEQA limit purposes. However, because the facilities are in RECLAIM, not only are they subject to BACT, but also to the holding requirement and the potential surrender of RTCs. The result is that if there aren't enough RTCs in the market, this proposed shave would effectively cap fuel use. By setting a concentration limit as well as a fuel use limit, this proposed shave would go beyond command and control regulations.

Response 11-2

The commenter states concerns with a potential shortage of credits as a result of the shave. As stated in the previous response, there are safety valves in the current rule and also in the rule proposal that would prevent this condition from occurring. For example, existing electric generating facilities would have access to non-tradable credits in the event that the 12-month rolling average threshold price trigger is reached or if a State of Emergency is declared. New electric generating facilities (in RECLAIM after October 15, 1993), would have access to a Regional NSR Holding Account to relieve them of NSR holdings requirements that often require holding excess credits at the potential to emit level, even though the actual emissions are far below this level. In addition, in the event of a power emergency, all electric generating facilities would have access to the Regional NSR account for credits used to offset these emissions during an emergency.

Comment 11-3

The amount of the shave could have impacts on grid reliability during emergency situations.

The current proposal contemplates what amounts to a 53% shave in the existing RTC market. While action must be taken to reduce current NOx emissions, this action must not result in a situation where generating facilities are unable to operate during emergency situations. The electric grid is a complex, interrelated system. All components work together to generate and ultimately distribute electric power to end users. If, for example, a major transmission line were to go down, there would be an immediate need for local, dispatchable generation to begin operating. If these facilities don't have sufficient RTCs to operate in these circumstances, the system would be faced with energy resources that could not be operated under SCAQMD rules, which would result in load curtailment. Because of the complexity of the system, there is no bright line that can be drawn. The District must therefore exercise caution and not bring about a market that is incapable of responding to emergency situations.

Response 11-3

The comment states that access to additional credits should be realized in a faster timeframe for unforeseen situations where emergency power generation may be necessary. Non tradable/non-usable RTCs are proposed to be accessed immediately if a State of Emergency is declared. Please refer to the response to Comment 11-2. Despite this, a facility would still have some time to reconcile all of its emissions at the end of a compliance year quarter, plus the reconciliation period.

Comment 11-4

Changes to the RATA testing requirements are supported

Thank you for meeting previously with SCE and DWP on this matter and recognizing that there was a legitimate need to change the rule language regarding postponement of RATAs. In the past, SCE has experienced multiple incidents where equipment has failed in the quarter in which a RATA was due, and found that the District's options for RATA postponement were impractical. With no reasonable alternative to postpone testing, and in order to avoid enforcement, the facilities were forced to petition the SCAQMD Hearing Board for variances. SCE believes the proposed language addresses this issue and now provides a legitimate alternative for RATA postponement without variance relief.

While we fully support the option presented, we are requesting an increase of the 14 unit operating day extension to 30 unit operating days. The main concern is with SCE's Pebbly Beach Generating Station on Catalina Island. Due to its remote location, weather related delays of transportation options to the island, and the high work load schedule of our source testing firm, it can be difficult to organize a RATA test in a short timeframe. The testing firm must separately schedule a time to barge its equipment out to the island, and if power demand on the island were high, the engines may need to run as soon as possible when they return to service, which could impact the test protocol This is especially true for the cleaner engines, as they must operate more frequently in order to comply with facility-wide emission limits. If the source testing firm could not schedule a visit to the island and the engines had to operate to support the power demand, 14 operating days might not be enough time to complete an appropriate RATA. As an alternative, if staff is not open to extending the 14 unit operating day window, SCE suggests having an equivalent operating hour limit. This could give the facility more time to schedule a test without increasing the overall operating time of the unit. Whether there are 14 days or 30 days to complete a RATA, a facility has plenty of incentive to complete the RATA as soon as possible so as to minimize the use of missing data procedures. We ask that the District consider this extension. But other than this amendment, we fully support the rule language as presented by the District and we appreciate the work done by staff to address this issue.

Response 11-4

The comment requests additional time for the extension of postponed RATA testing from 14 operating days to 30 operating days. The operating days do not have to be consecutive days so the total calendar days since the re-firing could be longer than 14 consecutive days.

Comment 11-5

SCE Supports the adjustment account for compliance with Rule 2005 Subdivision (f).
Existing USEPA interpretation of the NSR requirements hold that a facility in RECLAIM must obtain sufficient RTCs at the beginning of the calendar year to cover the total potential to emit (PTE) for the year notwithstanding that most facilities do not operate at or near their PTE. This results in a substantial procurement of RTCs that are necessarily bought at a time they are most expensive, but if not used are then sold off when they are of little value. Further, there is no environmental benefit created by what is, in effect, an over-procurement of credits. SCE supports the proposal by the District to create an adjustment account that would cover this RTC requirement. It would eliminate the costly procurement of RTCs beyond what is really needed to cover actual emissions and, quite simply, it makes sense. We urge the District to continue to seek EPA concurrence with this proposal.

Response 11-5

The comment expresses the support for the establishment of the Regional NSR Holding Account. We appreciate your support for these provisions affecting newer electric generating facilities with burdensome NSR holding requirements.

Comment Letter #12 – GE Capital & Inland Empire Energy Center Letter Dated September 22, 2015

Comment 12-1

Inland Empire Energy Center, LLC, a wholly-owned subsidiary of General Electric (GE), is the permit holder for the Inland Empire Energy Center (IEEC). GE purchased all NOx RTCs required for the IEEC instead of having them purchased by IEEC, LLC. The GE RTC account is, and always has been, 100% dedicated to the IEEC. Thus GE's NOx RRTC account should be designated as an Electric Generating Facility (non-refinery) account for purposes of the allocation shave. We therefore request that the GE RTC account be correctly categorized as an Electric Generating Facility (non-refinery) account in Table 8. Currently, GE is categorized as an "investor".

Response 12-1

The comment requests for the Investor account that is associated with Inland Empire Energy Center only to be categorized as an electric generating facility subject to the shave for the non-refinery sector. SCAQMD staff has reviewed the information you submitted and we agree that the investor account is associated with this electric generating facility only. The updated list of facilities will reflect the categorization of the investor account as a facility among the electric generating facilities affected by the shave. Table 8 of Rule 2002 will also be updated to reflect this change.

Comment Letter #13

Comment 13-1 The Shave for the Program Should be a Minimum of 14.85 tpd

We do not agree with the decision to reduce the total shave amount by 0.85 tpd, from the required 14.85 tpd to 14 tpd. California's Health & Safety Code is abundantly clear that trading programs must "result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations. . . ." Cal. Health & Safety Code §39616. In reviewing the materials produced through this rulemaking, the Best Available Retrofit Control ("BARCT") assessments show that a BARCT-equivalent program would result in 14.85 tpd fewer emissions. Accordingly, to comply with Health & Safety Code section 39616, the shave for the RECLAIM program must also be at least 14.85 tpd. We also suggest shaving even more from the program given the large size of the "black box" that must be reduced to meet ozone standards.

Response 13-1

SCAQMD staff understands the commenter's request for as many reductions as possible to be able to meet the attainment goals of the region. The reason that the overall RTC reduction is 14 tons per day and not more is to account for some BARCT uncertainties that arose in the refinery boiler and heater category. Staff and the consultant hired to do an independent BARCT assessment had some reasonable, but different engineering and cost assumptions which resulted in an adjustment to the staff proposal to account for this uncertainty.

Comment 13-2 The Implementation Schedule is Weak

We are deeply concerned that the schedule for implementation for the shave is too protracted. *See* Slide 4 of the Staff Presentation. Given recent difficulties in meeting various air quality standards, including the 1997 and 2006 standards for fine particle pollution ("PM2.5"), it would be prudent to move up some of the latter year reductions. In fact, we suggest amending the schedule to the following to ensure reductions on the front end in time for compliance with
Standards: 2016: 5tpd, 2018: 3 tpd, 2019: 3 tpd, 2020: 2 tpd, 2021: 1.85 tpd.

Response 13-2
Staff agrees with front loading some of the RTC reductions and has proposed a 4 ton per day reduction in 2016. The implementation schedule serves two purposes. The first is to address the SIP commitments to EPA regarding the contingency measure for 2016. The second is to ensure facilities have adequate time to install controls if that is how they choose to comply.

Comment 13-3 The District Should Not Establish a NSR Set Aside

Health Advocates do not support the implementation of a District-operated set-aside for New Source Review ("NSR") holdings. There is no basis for the District to undertake this task. In fact, this provision exists to ensure the program does not erode air quality progress in the region. We think this is a necessary safeguard, and we have not heard a compelling reason why the District should take on this duty. Industries have complied with this provision for decades, and it makes sense to continue to place this duty on industry.

Response 13-3

The commenter disagrees with the staff proposal to offer the Regional NSR Holding Account for ~~electrical~~ electricity generating facilities. The staff proposal aims to reduce the total allocation of the RECLAIM universe by over 53%. This is a very substantial reduction, much more so than the 22.5% reduction that resulted from the 2005 amendments to RECLAIM. ~~Electrical~~ Electricity generating facilities are in a unique situation in that they are all at either BARCT or BACT. In addition, the newer electric generating facilities have to meet the NSR holding requirements every year at the potential to emit level, even though the actual emissions are far below this level. While the staff proposal will shave those electric generating facilities among the top 90% of RTC holders by 49%, the Regional Account would provide some relief from their NSR holding obligations and help to maintain a functioning market in the event of a power emergency. This Regional Account would account for a small fraction of the overall proposed RTC reduction, which is designed to achieve BARCT-equivalent levels of emissions across the program.

Comment 13-4 The California Environmental Quality Act Analysis Should Examine a Command and Control Alternative

It is important that the Governing Board and the public receive full information on the environmental landscape of this action. In particular, through the California Environmental Quality Act (“CEQA”) process, an assessment of a Command and Control alternative will be important to understand how quickly desperately needed reductions could be implemented in the South Coast under a regulatory program requiring implementation of readily available technologies, many of which have not been installed at the largest NOx emitters in the South Coast. Under the currently proposed approach, clean up would be protracted for many years as the shave is implemented. A Command and Control Alternative would achieve reductions sooner than this compliance schedule.

Response 13-4

The commenter requests that a command and control alternative should be evaluated by CEQA. The purpose of the RECLAIM program is to allow emission reductions equivalent or greater to command and control at an equivalent or less cost. The BARCT analysis analyzed the technologies available to effect emission reductions that are cost effective and that are in compliance with the California Health and Safety Code. The actual control technologies to meet BARCT would be the same under command and control as assumed in the Project in the CEQA document, so the environmental impacts would be the same.

Comment 13-5

The claims of industry lobbyists that the IYB credits are appropriately priced are not true. In fact, like the short term credits, these credits are exceptionally low. Even with a more than doubling of the IYB prices in 2014 compared to 2013, these credits are only 18% of the $609,187 cost established by the District pursuant to section 39616(f) of the California Health & Safety Code, which is set to ensure credit prices do not go too high. That the failure of these IYB credits to even approach 1/5 of the District's ceiling for credit costs just bolsters the excessive number of credits in the NOx RECLAIM system. Overall, the evidence conclusively suggests that the credits are not priced correctly to push for pollution reductions at a level commensurate with what command and control would achieve, which is borne out in the District's BARCT assessments.

Response 13-5
Comment noted.

Comment 13-6 The Shave Approach Must Ensure Reductions from Refineries and Electric Generating Facilities.

The evidence presented by the District in this rulemaking indicates that refineries have used the NOx RECLAIM system as a shield from actually installing pollution control equipment like Selective Catalytic Reduction ("SCR"). Given this past behavior, we suggest that the best path forward is that refineries be taken out of the NOx RECLAIM program and be required to install pollution control equipment.

Response 13-6

The comment states that refineries should be removed from the RECLAIM program to force the installation of control equipment. As stated in the previous comment, the staff proposal is for a 53% overall RTC reduction from the RECLAIM universe. The refinery sector would experience a 66% RTC reduction. Staff believes that there is a sufficient impetus in the staff proposal to effect cost effective control technology installations at these facilities.

Comment Letter #14 Arnie Smith Email Dated August 11, 2015

Comment 14-1

At this point, we are probably one to two months away from having finalized NOx RECLAIM rules. Then, we are only another two months from the beginning of the first compliance year. There will be inadequate time for project development with any results in 2016/2017 - even for simpler scopes like burner replacements in existing heaters or catalyst upgrades in existing SCRs. But, new scrubbers or new SCRs would not be able to provide any mitigation benefit until 2018/2019.

The ongoing SOx RECLAIM Program had a gap of 26 months from the end of rule-making to the beginning of compliance - which would allow for some mitigation to be realized in the first compliance year. A three year gap would have insured an even stronger result.

A three year gap between rule-making and the first compliance year for NOx RECLAIM would have provided a better start for a real NOx reduction.

Response 14-1

The commenter expresses his concern that the proposed implementation schedule for the shave would provide inadequate time for projects to be completed and provided a reference to a document from the Association for the Advancement of Cost Estimating (AACE) that many engineering, procurement, and construction (EPC) firms use for designing their projects. The commenter uses the reference to illustrate that it takes many months of lead time and up to two to three years for emission reduction projects to be installed. Staff understands that there is a lead time associated with any construction project, but believes that the initial 4 ton per day reduction in 2016 would be satisfied by removing unused RTCs while still being able to provide the market with sufficient credits until further reductions in the allocation cap are realized. There is currently about a 28% margin from the allocation cap and the actual emissions. With a 4 ton per day reduction, it is anticipated that there would still be sufficient credits in the market to cover actual emissions. By 2018 when the next portion of the shave will be effective, several smaller projects would likely be installed, so when 2019 is reached, those larger projects that the commenter has referred to would be in place and would result in emissions under the allocation cap.

Comment Letter #15 Karl Lany Email Dated August 20, 2015

Comment 15-1

Thanks for taking the steps you have to accommodate Rule 219 boiler technology into the proposed RECLAIM amendments. After giving the concept more consideration, I continue to question the proposed requirement that such boilers be subject to testing requirements in order to qualify for RECLAIM reporting factors that reflects certification standards.

The entire SCAQMD program for certified diesel engines rests upon certification standards and excludes any emissions testing. It makes sense that the benefits of certification (exclusion from unnecessary emissions tests) that are extended to process unit diesel engines in RECLAIM would also be extended to permit exempt natural gas boilers that are subjected to a similar certification program.

I sincerely hope that SCAQMD reconsiders its proposed testing requirements for Rule 219 boilers in RECLAIM and instead provides a more practical solution that reflects the legitimacy of its boiler certification program.

Response 15-1

The commenter requests a reconsideration of the source testing requirements of small, unpermitted boilers in the staff proposal for usage of a lower emission factor for reporting Rule 219 equipment emissions. See Response 6-2.

Comment Letter #16 George Piantka Email Dated August 14, 2015

Comment 16-1

In Rule 2005, will there be proposed language to address annual holding limit requirements for a facility like Walnut Creek?

Response 16-1

The comment asks for proposed language for the affected facility. Staff is proposing to list the actual NSR holdings going into the Regional account year by year in Rule 2002 for those affected facilities. On the facility RECLAIM permits, Section B would still contain the usable/tradable and non-usable/non-tradable amounts, but the Regional account holdings will refer to the Rule 2002 as part of the permit conditions.

Comment 16-2

The financial impact to a new facility like Walnut Creek is different than an existing RECLAIM facility or new plant at an existing RECLAIM facility. In satisfying NSR (unlike a legacy RECLAIM facility), IYB Cycle 1 and 2 RTCs were purchased from the market. Demonstration that we satisfied the RTCs for annual NOx PTE was not only necessary for the Permit to Construct and annual Permit to Operate but also for the financing of the WCEP. We would now represent that the asset has lost the equivalent of 47% of its NOx IYB RTCs at the current rate of say $115/lb-yr and address the means to which we can demonstrate our continued holding and/or access to these RTC for the lenders. While not obvious, the financial implications are different than a facility that has relied on an existing RECLAIM account or the ability to reconcile its emissions for the respective year. It is the difference between losing the unrealized value of IYB RTCs in a legacy RECLAIM account versus the purchase, shave and possible replacement of them at the new market condition (or from the Regional NSR Holding Account?) to meet its PTE. This is one of the reasons why we believe WCEP should be exempt from the shave.

Response 16-2

The comment expresses concerns with the shave and its effect on a new facility that will continue to have NSR holding requirements every year. Staff acknowledges this situation for new electric generating facilities and the proposal includes provisions that would provide some relief for the NSR holding requirements with the establishment of the Regional NSR Holding Account.

Comment Letter #17 Chuck Casey Email Dated September 24, 2015

Comment 17-1

The list as provided in table U.1 needs to be audited with a full explanation of who is included or excluded and the reason for each. The NOx shave percentage adjusted for non-refinery RTC holders' weighted reduction, currently 47%, would require adjustment if the list changes.

Response 17-1

The commenter requests for a clarification on which electric generating facilities are part of the proposal for the shave and if cogeneration facilities are to be considered electric generating facilities for inclusion in the shave. SCAQMD staff has taken your comments into consideration and acknowledges that all electric generating facilities were included into the shave, even those under the 90% RTC Holders cutoff so that those with NSR holding obligations would be able to use the Regional NSR Holding Account. Upon further consideration, staff has removed those electric generating facilities that are under the 90% cutoff for RTC holders from the list of facilities for the shave.

Comment Letter #18 Los Angeles Department of Water and Power Dated August 14, 2015

Comment 18-1

The commenter feels that since its facilities are already at BARCT/BACT, cannot reduce power production to meet demand if there are no credits available, and could face a potential increase in NOx emissions due to transportation electrification, the current rule language for the conversion of non-tradable/non-usable RTCs to non-tradable/usable is inequitable and costly. LADWP recommends an alternative approach applicable to ~~electrical~~ electricity generating facilities such that the non-tradable/non-usable RTCs continue to be deemed non-tradable, but *usable* for compliance *without* the price threshold trigger.

Response 18-1

SCAQMD staff has taken these comments into consideration and has proposed a mechanism for accessing non-tradable/non-usable credits and also credits in the Regional NSR Holding Account with associated triggers. For the first year of the shave, the entire non-tradable/non-usable portion of a facility may be accessed if the rolling 12-month RTC price exceeds $22,500/ton. Those credits would become usable and tradable. The non-tradable/non-usable credits and the Regional NSR holding Account could also be accessed if the Governor of California declares a State of Emergency related to electricity demand or power stability in the Basin, but would be usable/non-tradable. Over time, the amount of RTCs in the Regional NSR Holding Account increases, and staff is not proposing a charge for use of these credits in the event of a power generating emergency declared by the Governor.

Staff is considering additional provisions for a faster responding price trigger to access the non-tradable/non-usable RTCs. Staff is also developing Governing Board adoption resolution language to direct staff to track the effects of increased electrification of transportation and penetration of renewable power sources on the electricity market, and report to the Stationary Source Committee annually with recommendations for program adjustments, if necessary.

These market safeguards will ensure that ~~electrical~~ electricity generating facilities have access to credits in the event of a power emergency without the curtailment of power, while also providing an alternative for these facilities to no longer participate in a market program. Staff is proposing rule language that would allow ~~electrical~~ electricity generating facilities whose equipment is at BACT or BARCT to opt out of the RECLAIM program. This would subject ~~electrical~~ electricity generating facilities to Command and Control rules.

Comment 18-2

LAWDP recommends that the 2022 NOx RTCs for power producing facilities not be submitted for inclusion into the State Implementation Plan in order to serve native load customers and anticipate future increased electrical demand.

Response 18-2

The commenter provides recommended alternative rule language for Proposed Rule 2002 (f)(1)(J) to not require RTCs reduced from ~~electrical~~ electricity generating facilities to be submitted into the SIP. The proposed rule language establishes the mechanism by which the non-tradable and Regional NSR accounts are handled. The non-tradable account is the yearly shaved amount of

RTCs. The rule language states that after one full compliance year the credits will be submitted into the SIP. For the first year of the shave, the non-tradable account can be accessed if the 12-month rolling average threshold price trigger is reached or if there is a State of Emergency. Existing power plants will also have access to their non-tradable/non-usable RTCs in a State of Emergency, as well as the credits in the Regional NSR Holding Account for subsequent years of the shave. Staff believes these safeguards would provide ~~electrical~~ electricity generating facilities with RTCs to meet their demand needs. In addition, staff is proposing to add language to the adoption Resolution directing staff to track the effects of increased electrification of transportation and penetration of renewable power sources on the electricity market, and report to the Stationary Source Committee annually with recommendations for program adjustments, if necessary. The RTCs in the Regional Holding Account will not be submitted in the SIP, and thus, if needed and with future rule amendments, could potentially be used to offset NOx emissions due to increased demand for electricity over the long term. Staff feels that this approach will provide the necessary program safeguards in lieu of not submitting the RTCs resulting from the 2022 NOx adjustment factors for ~~electrical~~ electricity generating facilities into the State Implementation Plan. Otherwise, the potential emission reductions represented by these RTCs could never be used for demonstrating attainment of the ozone or PM2.5 NAAQS, even though they may not be needed to offset actual emissions.

Comment 18-3

~~Electrical~~ Electricity generating facilities' ability to access RTCs in the Regional NSR Holding Account (formerly Adjustment Account) for the purposes of compliance is constrained due to the State of Emergency declaration. The rule language suggests that the RTCs in this account are limited after NSR requirements are met. This introduces great uncertainty whether there will be sufficient RTCs in this account. There are instances when LADWP must have its generating units available for operation in a short time frame to adjust to renewable production volatility. A "Reliability Coordinator" should have the authority to declare the State of Emergency and determine the distribution of RTCs. In addition, the staff report should explicitly state that the Regional NSR Holding Account RTCs would not be submitted to the State Implementation Plan.

Response 18-3

The comment expresses concerns on how the Regional NSR Holding account would function for ~~electrical~~ electricity generating facilities during a State of Emergency. The proposed rule language provides the mechanism by which access to these RTCs are given. Under a State of Emergency declaration, the current compliance year non-tradable/non-usable NOx RTCs may be used to offset emissions after exhausting the tradable/usable RTCs. If a facility has exhausted its non-tradable/usable RTCs, it may apply for the use of RTCs in the Regional NSR Holding Account. The facility requesting RTCs from the Regional account would submit a written request to the Executive Officer specifying the amount of RTCs needed. The Executive Officer will determine the amount and distribution of the RTCs from the Regional account based on certain criteria specified in the proposed amended rule. If there are not enough RTCs for all the power plants requesting relief, the RTCs will be distributed proportionately. These RTCs would be non-tradable, but usable to offset emissions, and thus not be submitted into the SIP.

The commenter also states that it may not be appropriate for the Executive Officer to determine the amount and distribution of RTCs and thereby make the determination of which power plants would generate electricity during a State of Emergency. Given the quarterly reconciliation period, staff believes there will be sufficient time and available RTCs for the Executive Officer to make findings and distribute RTCs to facilities soon after a short term power crisis. If the crisis is prolonged, there will be time to propose program adjustments and/or rule amendments to the Governing Board.

Staff believes that a major power crisis would warrant a State of Emergency declaration and not just an elevation in power demand. Staff understands that there are other factors to consider, such as the increase in the electrification in the transportation sector that may cause the demand to rise, as the commenter stated. Combined with the lesser amount of RTCs available as a result of the shave and higher resultant RTC prices, ~~electrical~~ electricity generating facilities may need some relief to gain access to more RTCs. Staff feels that the safety valves in the proposed amendment would address these concerns. Nonetheless, staff proposes to add resolution language to monitor the power-producing sector for trends in power consumption and associated NOx emissions as electricity demand potentially increases. If the State of Emergency is prolonged, the proposed amendments provide for a report to the Governing Board after any power crisis trigger such that a plan for distribution of RTCs and possible program adjustments can be made before the supply of emergency RTCs is exhausted.

The comment lastly states that the staff report should explicitly state that the RTCs in the Regional NSR Holding Account will not be submitted to the SIP. Both the rule language and the draft staff report state that these RTCs will not be submitted to the SIP.

Comment 18-4
LADWP recommends that the description "Gas Turbines" under the Nitrogen Oxides Basic Equipment column be amended to read "Refinery Gas Turbines" to distinguish that the Power Producing Facility gas turbines are not subject to BARCT in this rule amendment process.

Response 18-4
The commenter requests an amendment to the equipment description for gas turbines in Table 6 of proposed amended rule 2002. As part of the BARCT analysis, gas turbines in both the refinery and non-refinery sectors were analyzed for BARCT. In particular, there are some gas turbines in the non-refinery sector which produce power that are subject to BARCT. Thus, the description in Table 6 is broader than "Refinery Gas Turbines." The turbines at the ~~electrical~~ electricity generating facilities that the commenter refers to are not subject to BARCT because most of the units already operate at BACT, and this distinction is made in Appendix Q of the draft staff report that contains the BARCT analysis. Note that the amount of the reductions calculated for the proposed shave did not include any of the units that were already at or below the BARCT level.

Comment 18-5
The 14 operating day window for conducting a postponed RATA is insufficient. LADWP also requests that the clarification in the preliminary draft staff report that states that the proposed 14 operating day RATA postponement would apply separately for each unrelated, independent event also be placed in the rule language.

Response 18-5

The commenter had experienced multiple sequential failures to a unit which prompted the comment. Staff agrees that each unrelated independent event that rendered a major source incapable of operating separately qualifies for a postponement under this provision. Staff has revised the proposed rule to make this explicit. The commenter verbally expressed that this change satisfactorily addresses the concern regarding the length of time for conducting a RATA after the source is returned to service.

Comment 18-6
LADWP suggests that the semi-annual or annual assessment be allowed to be delayed even if the RATA was scheduled during the second 45 days of the calendar quarter in which the assessment was due, instead of being scheduled during the first 45 days of the calendar quarter as the current rule proposes.

Response 18-6
The operations of ~~electrical~~ electricity generating facilities are highly dependent on demand. RATA testing should be scheduled at the first opportunity available. Due to the unpredictability of electric demand, the schedule for operations is subject to change and actual operations that allow for RATA testing may not occur throughout an entire quarter. In those circumstances, the facility operator has exercised reasonable diligence in attempting to comply with RATA requirements, but failed to due to circumstances beyond its reasonable control. Therefore, the exemption is only offered in these cases. It is unreasonable to allow delay in conducting RATA if a facility operator decided to wait until the last part of the quarter to try and schedule a RATA. Staff explained this viewpoint to the commenter who has verbally accepted the reasoning.

Comment 18-7
The proposed requirement to disconnect and flange the fuel feed lines when a unit is physically incapable of operation and maintain operational fuel meters introduces health and safety issues, compromises structural integrity of the pipelines and would be costly at steam generating units scheduled to be replaced.

Response 18-7
SCAQMD staff discussed this issue with the commenter and agreed to incorporate language similar to the suggested language. The revised language did not make it into the version that was released October 6, 2015 but will be incorporated into the proposed amended rule that will be considered by the Governing Board.

Comment 18-8
LADWP presents a completely different alternative regulatory approach for consideration, which involves a credit mechanism by which ~~electrical~~ electricity generating facilities would have access to RTCs to support native load and transportation electrification. Two white papers are attached that detail this alternative approach and crediting mechanism, in addition to suggested resolution language addressing increased transportation electrification. Tradable RTCs would serve to address native load, and non-tradable RTCs would be allocated to cover increased generation due to mandatory and non-mandatory electrification measures. The tradable RTCs would not be adjusted, while the non-tradable RTCs would be adjusted to reflect the actual increased demand.

The SIP crediting mechanism is based on a similar approach that EPA has developed to incorporate energy efficiency and renewable energy strategies into SIP attainment strategies, which involves a quantification of NOx emission reductions that would be achieved from basin-wide electrification and a quantification of NOx emission increases from ~~electrical~~ electricity generating facilities to support this electrification.

Response 18-8

The commenter has presented an alternative approach, with supporting enclosures, which would address the increase in transportation electrification and the associated increase in electrical demand and NOx emissions. The framework of this mechanism, in part, involves the consideration of control measures for attainment strategies as part of the State Implementation Plan. The approach of the commenter's strategy is outside the scope of this rule making for RECLAIM. As detailed in the previous responses to this comment letter, the staff proposal outlines market safeguards that will help to address any possible market upset due to a shortage of credits, high RTC prices, and the potential increase in electrification basin-wide. The objective of the proposed project is to fulfill the obligation of 2012 AQMP control measure CMB-01, which is a reduction of RTCs from the NOx RECLAIM market based on a BARCT analysis. Under the staff proposal, if every unit subject to BARCT would install controls, there would still be a sufficient margin of credits available, comparable to the margin that exists today between the allocation cap and actual emissions. To attempt to quantify the anticipated increase in electrical demand due to the electrification of the transportation sector today would be speculative. The staff proposal has provided additional safeguards, such as the threshold price trigger for access to non-tradable RTCs and access to the Regional NSR Holding Account in the event of a major power emergency. The commenter's suggested resolution language has been noted and resolution language will be prepared that directs staff to monitor the power-producing sector for trends in power consumption and associated NOx emissions as electricity demand potentially increases.

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Comment Letter #19 Shell Energy North America (US), L.P. Letter Dated August 6, 2015

Comment 19-1

To meet the proposed amendments, the facility would need to make significant modifications to the SCR, CO catalyst, and to the exhaust modules housing the catalyst, far exceeding typical cost benefit ratios. The alternative emissions reduction choice would be to replace the combustor on the gas turbine, also cost prohibitive. There is no further cost effective NOx reduction technology for this facility. The only way that that such facilities can comply with the current proposed rule is to purchase additional NOx RTCs. This represents a significant expense for generating facilities especially considering the current market conditions in California, including the recent decommissioning of San Onofre Nuclear Generating Station. We request that SCAQMD consider that peaking generation facilities with lower capacity factor built to BACT should not be obligated under the proposed rule to make further emissions reductions, and allow the emissions offsets previously procured for the unit to meet current and future SCAQMD requirements.

Response 19-1

The comment requests that the facility in question should not be required to make further emission reductions and allow the use of NSR offset credits to meet current and future SCAQMD requirements. The staff proposal includes facilities that hold credits that are in the top 90% of all the RTC holders in the NOx RECLAIM universe. Since this facility is among those facilities in the top 90%, it would be subject to a shave of 49%. A peaking facility such as the one the commenter is referring to is in a similar situation as other ~~electrical~~ electricity generating facilities that are subject to NSR requirements, have emissions that are far below what they need to hold for NSR purposes, and have RTC holdings that significantly exceed their actual emissions. It is for this specific purpose that the Regional NSR Holding Account was created to assist in facilities meeting their NSR obligation without going to the market to purchase credits. As explained in the proposed rule language and in other responses to comments, a newer ~~electrical~~ electricity generating facility subject to NSR holding requirements would have the shaved credits put into the Regional account, and the exact quantities are listed for each of the affected facilities in Table 9 of Rule 2002 for every year of the shave. It is not expected that such facilities install further controls since most the equipment is already either at BARCT or BACT. The proposed rule has safeguards that can make non-tradable credits and Regional NSR Holding Account credits available under certain specific conditions in the event of an unstable market or in a major power emergency. Staff is also proposing rule language that would allow ~~electrical~~ electricity generating facilities whose equipment is at BACT or BARCT to opt out of the RECLAIM program. This would subject ~~electrical~~ electricity generating facilities to Command and Control rules.

Comment 19-2

We believe that the Date of Amendment (the date that RTC holdings will be adjusted (should be set closer to or upon the actual date when the final Rule is published. Additionally, it is not clear how the March 20, 2015 date was established and does not address how NOx RTCs that were transferred between March 20, 2015 and the date of implementation of the Proposed Rule will be treated. We request that the SCAQMD act prospectively; the NOx RTC holdings should be the quantity as of the date of the implementation of the Proposed Rule.

Response 19-2

The commenter requests that the freeze date of the RTC holdings be changed to the date of the rule implementation. Staff has revised the proposal and notified the stakeholders regarding the proposed new freeze date of September 22, 2015. Staff cannot practically make the freeze date for shave estimation the date of rule adoption because the rule language and calculation of shave must be completed for public review and comment prior to the Governing Board hearing for rule adoption. Note that the March date was retained for determining which facilities were in the top 90%, but the freeze date was changed due to stakeholder input.

Comment 19-3

Additional information and clarification is needed regarding the Proposed Regional NSR Holding Account for Generators PAR 2000 (f) (4).

Response 19-3

The commenter requests additional clarity and information regarding the Regional NSR Holding Account for newer ~~electrical~~ electricity generating facilities subject to NSR holding requirements. The proposed rule language has been revised to provide clarity as to how the Regional account will be funded and accessed. Table 9 in Rule 2002 contains the list of affected facilities with NSR holdings with a yearly balance of RTCs that will go into the account. Further discussion regarding the proposed amendments is contained in Appendix X of the draft staff report.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

November 2015

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State Clearinghouse No: 2014121018

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PREFACE

This document constitutes the Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM). A Notice of Preparation/Initial Study (NOP/IS) was released for a 57-day public review and comment period from December 5, 2014 to January 30, 2015 which identified the environmental topics of aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic, as potentially being significantly adversely affected by the project. Eight comment letters were received from the public regarding the preliminary analysis in the NOP/IS. The comment letters received relative to the NOP/IS and responses to individual comments are included in Appendix G of this document.

The Draft PEA was released for a 53-day public review and comment period from August 14, 2015 to October 6, 2015 which identified the topics of topics of air quality and GHGs, hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) as exceeding the SCAQMD's significance thresholds associated with implementing the proposed project. Eight comment letters were received from the public regarding the analysis in the Draft PEA. The comment letters received relative to the Draft PEA and responses to individual comments are included in Appendix I of this document.

In addition, subsequent to release of the Draft PEA, modifications were made to the proposed project and some of the revisions were made in response to verbal and written comments received. To facilitate identification, modifications to the document are included as underlined text and text removed from the document is indicated by ~~strikethrough~~. To avoid confusion, minor formatting changes are not shown in underline or strikethrough mode.

Staff has reviewed the modifications to the proposed project and concluded that none of the revisions constitute: 1) significant new information; 2) a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the draft document. In addition, revisions to the proposed project in response to verbal or written comments would not create new, avoidable significant effects. As a result, these revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5. Therefore, this document now constitutes the Final PEA for the proposed project.

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CHAPTER 1

EXECUTIVE SUMMARY

Introduction

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Executive Summary

1.0 INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the District. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the District[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The Final 2012 AQMP concluded that reductions in emissions of particulate matter (PM), oxides of sulfur (SOx), oxides of nitrogen (NOx), and volatile organic compounds (VOC) are necessary to attain the state and national ambient air quality standards for ozone, and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5). Ozone, a criteria pollutant which has been shown to adversely affect human health, is formed when VOCs react with NOx in the atmosphere. VOCs, NOx, SOx (especially sulfur dioxide) and ammonia also contribute to the formation of PM10 and PM2.5.

The Basin is designated by the United States Environmental Protection Agency (EPA) as a non-attainment area for PM2.5 emissions because the federal PM2.5 standards have been exceeded. For this reason, the SCAQMD is required to evaluate all feasible control measures in order to reduce direct PM2.5 emissions, as well as PM2.5 precursors, such as NOx and SOx. The Final 2012 AQMP sets forth a comprehensive program for the Basin to comply with the federal 24-hour PM2.5 air quality standard, satisfy the planning requirements of the federal Clean Air Act, and provide an update to the Basin's commitments towards meeting the federal 8-hour ozone standard. In particular, the Final 2012 AQMP contains a multi-pollutant control strategy to achieve attainment with the federal 24-hour PM2.5 air quality standard with direct PM2.5 and NOx reductions identified as the two most effective tools in reaching attainment with the PM2.5 standard. The 2012 AQMP also serves to satisfy the recent requirements promulgated by the EPA for a new attainment demonstration of the revoked 1-hour ozone standard, as well as to provide additional measures to partially fulfill long-term reduction obligations under the 2007 8-hour Ozone State Implementation Plan (SIP).

As part of this ongoing PM2.5 reduction effort, SCAQMD staff is proposing amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements and to modify the RECLAIM trading credit (RTC) "shaving" methodology. The primary focus of the proposed project is to bring the NOx RECLAIM program up-to-date with the latest BARCT requirements while achieving the proposed NOx emission reductions in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM (e.g., at least three to five tons per day by 2023). In addition, the proposed project is designed to implement both the Phase I and Phase II reduction commitments described in #CMB-01.

Control measure CMB-01 included an initial estimate of two to three tons per day of NOx emission reductions. However, further analysis of the actual BARCT NOx emission control opportunities for the various equipment/process categories demonstrated that the proposed project could achieve 14 tons per day of NOx emission reductions by 2023 which is much higher

1 The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health and Safety Code, §§40400-40540).
2 Health and Safety Code, §40460 (a).
3 Health and Safety Code, §40440 (a).

than estimates provided in the 2012 AQMP. Higher NOx emission reductions will further assist in attaining the national ambient air quality standards evaluated in the 2012 AQMP.

The proposed project will apply to the following types of equipment/source categories in the NOx RECLAIM program: 1) fluid catalytic cracking units (FCCUs); 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units (SRU/TGUs); 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines (ICEs); 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RECLAIM RTCs and NOx RTC adjustment factors for year 2016 and later. Other minor changes are proposed for clarity and consistency throughout the proposed amended regulation.

The overall NOx emission reductions of 14 tons per day are expected to be achieved incrementally from 2016 to 2022. In particular, the proposed project is estimated to reduce RTCs by four tons per day of NOx emissions or more starting in 2016 and continuing with an additional reduction of two tons per day of NOx for years 2018 through 2022. Despite this projected direct environmental benefit to air quality, the Notice of Preparation (NOP) and Initial Study (IS), prepared pursuant to the California Environmental Quality Act (CEQA), identified the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic. This ~~Draft~~ Final Program Environmental Assessment (PEA) has been prepared to analyze further whether the potential impacts to these environmental topics are significant.

1.1 CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA), California Public Resources Code §21000 *et seq.*, requires environmental impacts of proposed projects to be evaluated and feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects to be identified and implemented. The lead agency is the "public agency that has the principal responsibility for carrying out or approving a project that may have a significant effect upon the environment" (Public Resources Code §21067). Since the SCAQMD has the primary responsibility for supervising or approving the entire project as a whole, it is the most appropriate public agency to act as lead agency (CEQA Guidelines[4] §15051 (b)).

CEQA requires that all potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the lead agency, responsible agencies, decision makers and the general public of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures or alternatives, when an impact is significant.

Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989, and has been adopted as

[4] The CEQA Guidelines are codified at Title 14 California Code of Regulations, §15000 et seq.

SCAQMD Rule 110 – Rule Adoption Procedures to Assure Protection and Enhancement of the Environment.

CEQA includes provisions for the preparation of program CEQA documents in connection with issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program, including adoptions of broad policy programs as distinguished from those prepared for specific types of projects such as land use projects, for example (CEQA Guidelines §15168). A program CEQA document also allows consideration of broad policy alternatives and program-wide mitigation measures at a time when an agency has greater flexibility to deal with basic problems of cumulative impacts (CEQA Guidelines §15168 (b)(4)). Lastly, a program CEQA document also plays an important role in establishing a structure within which CEQA review of future related actions can effectively be conducted. This concept of covering broad policies in a program CEQA document and incorporating the information contained therein by reference into subsequent CEQA documents for specific projects is known as "tiering" (CEQA Guidelines §15152).

A program CEQA document, by design, provides the basis for future environmental analyses and will allow future project-specific CEQA documents, if necessary, to focus solely on the new effects or detailed environmental issues not previously considered. If an agency finds that no new effects could occur, or no new mitigation measures would be required, the agency can approve the activity as being within the scope of the project covered by the program CEQA document and no new environmental document would be required (CEQA Guidelines §15168 (c)(2)).

The proposed amendments to Regulation XX are considered a "project" as defined by CEQA. The proposed project will reduce NOx emission and will provide an overall environmental benefit to air quality. However, SCAQMD's review of the proposed amendments also shows that implementation of the proposed project may also have a significant adverse effect on the environment.

In addition, because the proposed amendments to Regulation XX and their subsequent implementation: 1) are connected to the issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program (CEQA Guidelines §15168 (a)(3)); and, 2) contain a series of actions that can be characterized as one large project and the series of actions are related as individual activities that would be carried out under the same authorizing regulatory authority and having similar environmental effects which can be mitigated in similar ways (CEQA Guidelines §15168 (a)(4)), the type of CEQA document appropriate for the proposed project is a Program Environmental Assessment (PEA). The PEA is a substitute CEQA document, prepared in lieu of a program environmental impact report (EIR) (CEQA Guidelines §15252), pursuant to the SCAQMD's Certified Regulatory Program (CEQA Guidelines §15251 (l); codified in SCAQMD Rule 110). The PEA is also a public disclosure document intended to: 1) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental impacts of the proposed project; and, 2) be used as a tool by decision makers to facilitate decision making on the proposed project.

The first step of preparing a Draft PEA is to prepare a Notice of Preparation (NOP) with an Initial Study (IS) that includes an Environmental Checklist and project description. The Environmental Checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. The NOP/IS is also intended to provide information about the proposed project to other public agencies and interested parties prior to the release of the Draft PEA.

On December 5, 2014, the SCAQMD, as Lead Agency for the proposed project, released a NOP/IS for the proposed project for a 57-day public review and comment period which ended on January 30, 2015. Since the proposed project may have statewide, regional or areawide significance, a CEQA scoping meeting is required and was held for the proposed project pursuant to Public Resources Code §21083.9 (a)(2) on January 8, 2015~~4~~. The evaluation in the NOP/IS identified the topics of aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic, as potentially being adversely affected by the proposed project.

During the NOP/IS public comment period, the SCAQMD received eight comment letters relative to the CEQA analysis. These letters and their responses can be found in Appendix G of this document. In addition, Appendix H of this ~~Draft~~ PEA summarizes the comments received at the CEQA Scoping Meeting held on January 8, 2015 and the responses to the comments.

The Draft PEA was released for a 53-day public review and comment period from August 14, 2015 to October 6, 2015. In accordance with CEQA Guidelines §15064 and §15168, SCAQMD has prepared this ~~Draft~~ Final PEA to evaluate the potentially significant adverse impact topics that were identified in the NOP/IS (e.g., aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic) for the proposed project. This ~~Draft~~ Final PEA further analyzes whether or not the potential adverse impacts to these environmental topic areas are significant. The ~~Draft~~ Final PEA concluded that only the topics of air quality and GHGs, hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) would have significant adverse impacts.

Eight ~~Any~~ comment~~s~~ letters were received during the public comment period on the analysis presented in the~~is~~ Draft PEA. Responses to these comment letters have been prepared. The comment letters along with the responses are ~~will be responded to and~~ included in Appendix I of this~~e~~ Final PEA. Subsequent to release of the Draft PEA, modifications were made to the proposed project and some of the revisions were made in response to verbal and written comments received. Staff has reviewed the modifications to the proposed project and concluded that none of the modifications constitute: 1) significant new information; 2) a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the draft document. In addition, revisions to the proposed project in response to verbal or written comments would not create new, avoidable significant effects. As a result, these revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5.

Thus, this Final PEA, prepared pursuant to CEQA Guidelines §15132, identifies air quality and GHGs, hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) as areas that may be adversely affected by the proposed project. Prior to making a decision on the adoption of the proposed amendments to Regulation XX, the SCAQMD Governing Board must review and certify the Final PEA as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting the proposed amendments to Regulation XX.

1.2 PREVIOUS CEQA DOCUMENTATION FOR REGULATION XX

This ~~Draft~~ Final PEA is a comprehensive environmental document that analyzes potential environmental impacts from the proposed amendments to Regulation XX. SCAQMD rules, as ongoing regulatory programs, have the potential to be revised over time due to a variety of factors (e.g., regulatory decisions by other agencies, new data, and lack of progress in advancing the effectiveness of control technologies to comply with requirements in technology forcing rules, etc.). Several previous environmental analyses have been prepared to analyze past amendments to the rules that comprise Regulation XX. The following paragraphs summarize these previously prepared CEQA documents and are included for informational purposes only. The current ~~Draft~~ Final PEA focuses on the currently proposed amendments to Regulation XX and does not rely on these previously prepared CEQA documents. The following documents can be obtained by submitting a Public Records Act request to the SCAQMD's Public Records Unit. In addition, a link for downloading files from the SCAQMD's website is provided for those CEQA documents prepared after January 1, 2000. The following is a summary of the contents of these documents, in reverse chronological order.

Notice of Exemption From CEQA for Proposed Amended Rule 2005 – New Source Review For RECLAIM; June 2011: The amendments to Rule 2005 – New Source Review For RECLAIM, changed the RECLAIM Trading Credit (RTC) hold requirement for an existing RECLAIM facility, provided its emission level stays below the level of its starting Allocations plus non-tradable credits. The amendment requires an existing RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but does not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits. The offset requirements for new RECLAIM facilities remained unchanged. The SCAQMD concluded that the amendments to Rule 2005 would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. In addition, the SCAQMD concluded that the amendments were categorically exempt because they were considered actions to protect or enhance the environment pursuant to CEQA Guidelines §15308 – Action by Regulatory Agencies for the Protection of the Environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/docs/default-source/ceqa/notices/notices-of-exemption/2011/2005noegeneral.pdf?sfvrsn=2

Final Program Environmental Assessment (PEA) for proposed amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM); November 2010 (SCAQMD Number 06182009BAR / SCH Number 2009061088): A Draft PEA was prepared for amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), were adopted to would reduce the allowable SOx emission limits based on current Best Available Retrofit Control Technology (BARCT) for the following industrial equipment and processes: 1) petroleum coke calciners; 2) cement kilns; 3) coal-fired boiler (cogeneration); 4) container glass melting furnace; 5) diesel combustion; 6) fluid catalytic cracking units; 7) refinery boilers/heaters; 8) sulfur recovery units/tail gas treatment units; and, 9) sulfuric acid manufacturing. Additional amendments were made that established procedures and criteria for reducing RECLAIM Trading Credits (RTCs) and RTC adjustment factors for year 2013 and later. The Draft PEA was released for a 45-day public review period from August 18, 2010 to October 1, 2010. The Draft PEA identified the topics of air quality and hydrology (water demand) as the only areas that may be significantly adversely affected by the project. After circulation of the Draft PEA, a Final PEA was prepared and certified by the SCAQMD Governing Board on November 5, 2010. This document can be obtained by visiting the following website at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2010/final-program-environmental-assessment-for-proposed-amended-regulation-xx.pdf?sfvrsn=4

Notice of Exemption From CEQA for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM); April 2007: The amendments to Regulation XX – RECLAIM were administrative in nature and focused on the following rules: Rule 2004 – Requirements; Rule 2007 – Trading Requirements; and Rule 2010 – Administrative Remedies and Sanctions. The amendments to Rule 2004 provided an exemption from submitting Quarterly Certification Emission Reports for facilities that do not have any NOx or SOx emitting equipment located on site. The amendments to Rule 2007 clarified the trading requirements for foreign entities that are not residing or licensed to conduct business in California, and clarified reporting requirements for parties entering into a forward contract or a contingent right contract. Amendments to Rule 2010 specified liability for allocation violations when changes of ownership occur. Other minor administrative changes were included that improved the clarity of these rules. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061(b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/docs/default-source/ceqa/notices/notices-of-exemption/2007/noe-proposed-amended-regulation-xx-rules-2004-2007-2010.pdf?sfvrsn=2

Notice of Exemption From CEQA for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM); May 2005: The amendments to Regulation XX – RECLAIM were administrative in nature and focused on the following rules and protocols: Rule 2000 – General; Rule 2001 – Applicability; Rule 2005 – New Source Review for RECLAIM; Rule 2007 – Trading Requirements; Protocol for Rule 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions; and Protocol for Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions. Amendments to Rule 2000 and Protocols for Rules 2011 and 2012 were proposed for consistency with the new source requirements for non-RECLAIM sources and for clarification that mobile source emissions are part of the total RECLAIM pollutants emitted from a facility. Amendments to Rule 2005 clarified that emissions from affected sources shall include mobile source emissions and to include an alternative quarterly holding period for RTCs for offsetting emissions from a new source. Amendments to Rule 2007 reinstated the trading provision that would allow power producers to transfer NOx RECLAIM Trading Credits among facilities under common ownership which was inadvertently omitted during the January 7, 2005 amendments to Rule 2007. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the proposed project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to

CEQA Guidelines §15061(b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/home/library/public-information/noe-archive/noe---year-2005

Final Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM); December 2004 (SCAQMD No. 031104BAR): A Draft Environmental Assessment (EA) for amendments to Regulation XX (Rule 2001 – Applicability; Rule 2002 – Allocations for NOx and SOx; Rule 2007 – Trading Requirements; Rule 2009 – Compliance Plans for Power Producing Facilities; Rule 2010 – Administrative Remedies and Sanctions; Rule 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for SOx Emissions; and, Appendix A – Protocol for SOx; and, Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions; and, Appendix A – Protocol for NOx) was released for a 45-day public review period from October 22, 2004 to December 7, 2004. The amendments implemented control measure CMB-10 in the 2003 AQMP and addressed BARCT requirements to achieve additional NOx emission reductions. The Draft EA identified the topic of air quality as the only area that may be significantly adversely affected by the project. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on January 7, 2005. This document can be obtained by visiting the following website at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2005

Notice of Exemption From CEQA for Proposed Amended Rule 2007 – Trading Requirements; September 2004: The purpose of the amendments to Rule 2007 was to address CARB concerns regarding the reintroduction of power plants to the RECLAIM trading market. The proposal contained a provision that delayed the date when the trading restrictions would be lifted until such time that other RECLAIM rule amendments (scheduled for January 2005) were adopted that would decrease allocations to implement the 2003 AQMP Control Measure CMB-10 and to reflect BARCT in accordance with Health and Safety Code (HSC) §40440. The air quality objective was to ensure that BARCT adjustments are made to facility allocations prior to removal of power plant trading restrictions. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/home/library/public-information/noe-archive/noe---year-2004

Notice of Exemption From CEQA for Proposed Amended Rule 2015 – Backstop Provisions; June 2004: The purpose of the amendments to Rule 2015 was to address the USEPA's conditional approval of Regulation XX – RECLAIM, as amended May 11, 2001. The USEPA determined that the accounting procedures for and mitigations of excess emissions that occur during a breakdown in the current version of the RECLAIM program needed to be modified because these provisions conflict with USEPA's 1999 'Excess Emissions Policy' and §110 and Part D of the federal Clean Air Act (CAA). Specifically, the amendments to Rule 2015: 1) required the SCAQMD to monitor excess emissions occurring during breakdowns that are not covered by facility RTCs, and to compare that amount to the quantity of available, unused RTCs each year for the entire RECLAIM program; and, 2) required offsets for excess unmitigated breakdown emissions. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/home/library/public-information/noe-archive/noe---year-2004

Addendum to May 2001 Final Environmental Assessment for Proposed Amended Rule 2007 – Trading Requirements; Proposed Amended Rule 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for SOx Emissions; and, Proposed Amended Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions; October 14, 2003 (SCAQMD No. 101403BAR): The amendments to Rule 2007 required the power producers to re-enter the RECLAIM trading market. Specifically, the power producing facilities were brought back into the RECLAIM trading market and allowed to use RTCs to reconcile emissions, and to sell or transfer RTCs below the original allocation after compliance year 2003. The amendments to Rules 2011 and 2012 clarified that the 90-day recertification period for Continuous Emission Monitoring Systems (CEMS) applies when a new CEMS or a component of an existing CEMS is added to an existing or modified major RECLAIM source. An Addendum to the May 2001 Final EA for the amendments to Regulation XX (Rules 2007, 2011, and 2012) was prepared. The SCAQMD determined that an Addendum to the May 2001 Final EA was the appropriate document to prepare because none of the conditions described in CEQA Guidelines §15162 were triggered since the amendments did not contain new information of substantial importance and would not create any new significant adverse impacts or substantially increase the severity of the previously identified significant environmental effects in the original project. Further, the SCAQMD concluded that the amendments would not change the environmental analysis or conclusions in the previously certified May 2001 Final EA. Pursuant to CEQA Guidelines §15164 (c), it was not necessary to circulate the Addendum for public review. The Addendum to the May 2001 Final EA was certified by the SCAQMD Governing Board on December 5, 2003. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2003

Final Environmental Assessment for Proposed New and Amended Rules, Regulation XX – RECLAIM; Rule 1631 – Pilot Credit Generation Program for Marine Vessels; Rule 1632 – Pilot Credit Generation Program for Hotelling Operations; Rule 1633 – Pilot Credit Generation Program for Truck/Trailer Refrigeration Units; and Rule 2507 – Pilot Credit Generation Program for Agricultural Pumps; May 2001 (SCAQMD No. 010201JDN): An integrated group of new and amended rules were adopted to help ensure compliance with emission allocations contemplated during initial RECLAIM program design while reducing impacts of California's electricity crisis on the RECLAIM market. The project included proposed new and amended RECLAIM rules and four voluntary mobile and area source NOx pilot credit generation rules. The project components were designed to work together to lower and stabilize RTC prices by increasing supply, reducing demand, and increasing RTC trading information availability and accuracy. A Draft EA for the amendments to Regulation XX plus proposed Rules 1631, 1632, 1633 and 2507 (which established pilot NOx credit generation rules as a means of creating additional NOx RTCs) was released for a 30-day public review period from March 27, 2001 to April 25, 2001. The analysis showed that there were potential adverse environmental effects that may result from implementing the amendments (primarily removing power producers from the trading market). The Draft EA identified "air quality" and "hazards and hazardous materials" as the only areas that may be significantly adversely affected by the project. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on May 11, 2001. This document can be obtained by visiting the following website at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2001/fea-for-proposed-new-and-amended-regulation-xx

Final Environmental Assessment for Proposed Amended Rules 1303 – Requirements, 2005 – New Source Review for RECLAIM, 1302 - Definitions and 1309.1 - Priority Reserve; April 9, 2001 (SCAQMD No. 021401MK): The amendments to Rules 1303 and 2005 revised the modeling standard for sources locating in an attainment sub-region of the district so that any proposed new emissions plus the measured background could not create a violation of any applicable ambient air quality standard. In sub-regions designated as nonattainment areas for specified criteria pollutants, the modeling criteria remained the same, but emissions from new or modified sources were not allowed to exceed the allowable change in concentration thresholds as set forth in Rule 1303, Table A-2. The amendments to Rule 1309.1 allowed temporary access to the SCAQMD's Priority Reserve PM10 account for new electric generating facilities (EGF) for applications deemed complete between 2001 and 2003, provided that all the other requirements were met and the appropriate mitigation fee was paid. The Draft EA was released for a 30-day public review and comment period from February 14, 2001 to March 15, 2001. The Draft EA concluded that the project would not have any significant or potentially significant effects on the environment. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on April 20, 2001. This document can be obtained by visiting the following website at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2001

Notice of Exemption From CEQA for Proposed Amended Rule 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions; and, Proposed Amended Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions; March 2001: Because the substantive components of the project involved the addition of an alternative recordkeeping option, the SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared. This document can also be obtained by visiting the following website at: http://www.aqmd.gov/home/library/public-information/noe-archive/noe---year-2001

Final Environmental Assessment for Proposed Amended Rules 1302 – Definitions, 1303 – Requirements, 1306 – Emissions Calculations, 2000 – General; and BACT Guidelines; August 23, 2000 (SCAQMD No. 33100JDN): The amendments bifurcated the New Source Review (NSR) control technology requirements into Lowest Achievable

Emission Rate (LAER) for federal major polluting facilities and Minor Source Best Available Control Technology (MSBACT) for all others. Unlike federal LAER, state law allows the cost of the control equipment to be taken into consideration when making a BACT determination. All major polluting facilities, as defined in the federal CAA, would continue to be required to employ LAER for a new or relocated source and any emission increase from a modified source. All other facilities would be required to employ MSBACT. The amendments applied to both RECLAIM and non-RECLAIM sources. Additionally, the amendments allowed relocations of non-major polluting facilities that meet certain conditions, including no emission increases upon relocation and for two years thereafter, to maintain the existing control level from the prior location instead of requiring the installation of new BACT controls. The Draft EA was released for a 30-day public review and comment period from July 11, 2000 to August 9, 2000. The Draft EA concluded that the project would not have any significant or potentially significant effects on the environment. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on October 20, 2000. This document can be obtained by visiting the following website at: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2000

Notice of Exemption for Proposed Amended Rule 2005 - New Source Review for RECLAIM, Rule 2011 - Requirements for Monitoring, Reporting, and Recordkeeping for SOx Emissions, and Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions; April 1999: The amendments included clarifications to New Source Review requirements for change of operator and modifications to new facilities. For major sources, the amendments clarified monitoring requirements and added calculation methods for cases currently not addressed. For large sources, the amendments added monitoring and calculations methods for cases currently not addressed and clarified source testing requirements. For process units, the amendments established concentration limits for determining emissions and added guidelines for category specific emission rates. The amendments also corrected rule references, extended deadlines for monthly emissions reporting, and added clarifying language to enhance enforcement and consistency. The amendments were necessary to clarify rule requirements and improve enforceability. The amendments also increased flexibility for RECLAIM facilities. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared.

Notice of Exemption for Proposed Amended Rule 2000 - General, Rule 2011 - Requirements for Monitoring, Reporting and Recordkeeping for SOx Emissions and Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions; April 1997: The amendments clarified the rule requirements for emissions from contractors' equipment at RECLAIM facilities by: 1) adding a definition for contractor; 2) specifying that emissions from contractors' equipment should be accounted for by the RECLAIM facility in the same manner as emissions from rental equipment, with the exception of specific processes that do not contribute to a facility’s manufacturing process; and, 3) excluding emissions from certain contractors' equipment at a Super Compliant facility. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared.

Notice of Exemption for Proposed Amended Rule 2000 - General, Rule 2001 - Applicability, Rule 2002 - Allocations for NOx and SOx, Rule 2005 - New Source Review for RECLAIM, Rule 2011 - Requirements for Monitoring, Reporting and Recordkeeping for SOx Emissions, Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions and Rule 2015 - Backstop Provisions; February 1997: The amendments modified requirements for non-operating and infrequently-operated major sources, exemption provisions, emission factors, and certain monitoring, reporting, and recordkeeping (MRR) requirements. The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared.

Final Supplemental Environmental Assessment for Proposed Amended Rule 2002 - Allocations for NOx and SOx, Rule 2004 - Requirements, Rule 2005 - New Source Review for RECLAIM, Rule 2011 - Requirements for Monitoring, Reporting, and Recordkeeping for SOx Emissions, Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions, and Rule 2015 - Backstop Provisions; June 1996: The amendments clarified rule requirements and improved monitoring, reporting, and recordkeeping flexibility for RECLAIM facilities. The amendments provided: 1) procedures consistent with Rule 430 - Breakdown Provisions; 2) procedures for reporting equipment breakdowns affecting RECLAIM pollutants; 3) more accurate emission factors; 4) clarifications of RTC allocations after year 2010; 5) consolidated requirements for reports on RECLAIM issues; 6) clarified requirements for Super Compliance facilities; 7) a period of time for CEMS repairs; 8) clarifications of monitoring, reporting, recordkeeping, and other requirements; and, 9) an alternative to the NOx ending emission factor for cement kilns based on a demonstration plan. Pursuant to CEQA, the SCAQMD prepared a Draft Supplemental Environmental Assessment (SEA) for the amendments to Regulation XX - RECLAIM. The Draft SEA was a supplement to the October 1993 Final EA for Regulation XX (SCAQMD No. 930524SS) and was circulated for a 45-day public review and comment period that ended May 10, 1996. The Final SEA was certified by the SCAQMD Governing Board on July 12, 1996.

Notice of Exemption for Proposed Amended Rule 1303 - Requirements (New Source Review) and Rule 2005 - New Source Review for RECLAIM; May 1996: The amendments incorporated protection of visibility for Federal Class I areas into Regulations XIII and XX. Protection of visibility for Federal Class I areas and notification of Federal Land Managers are requirements of federal law. The SCAQMD determined that the amendments were exempt from CEQA pursuant to CEQA Guidelines §15308 - Action by Regulatory Agencies for the Protection of the Environment, since the activity was covered by this Class 8 exemption for actions to assure the maintenance, restoration, enhancement, or protection of the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared.

Final Supplemental Environmental Assessment for Proposed Amended Regulation XX – RECLAIM; December 1995: The Final Supplemental EA for Regulation XX addressed the potential air quality, energy and risk of upset impacts associated with the exemption of two facilities from the RECLAIM program, State Implementation Plan (SIP) approvability issues and the allocation revision for one facility participating in the program. Air quality was the only environmental area determined to be adversely impacted from the amendments. The air quality impacts resulted from removing two facilities from the RECLAIM program and the loss of anticipated NOx emission reductions from the allocation revisions. A Statement of Findings and Overriding Considerations were prepared for the project.

Notice of Exemption for Proposed Amended Rule 2011 - Requirements for Monitoring, Reporting and Recordkeeping for SOx Emissions, and Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for NOx Emissions; September 1995: The SCAQMD concluded that the amendments would not have an effect on emissions and that there was no possibility that the project would have the potential to have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15061 (b)(3) - Review for Exemption, the project was determined to be exempt from CEQA and a Notice of Exemption was prepared.

Final Supplemental Environmental Assessment for Proposed Amended Rule 2002 - Allocations for NOx and SOx; March 1995: The Final EA for Rule 2002 addressed the potential air quality and energy impacts from adjusting the years 2000 and 2003 Allocations for the petroleum coke calcining industry. Air quality was the only area determined to be adversely impacted from the amendments due to the loss of future emission reductions. A Statement of Finding and Overriding Considerations was prepared for the amendments.

Final Environmental Assessment for the Proposed Adoption of Regulation XX - RECLAIM; October 1993: A Draft EA for the proposed NOx and SOx RECLAIM program, comprised of three volumes: Volume I - Development Report and Proposed Rules, Volume II - Supporting Documentation and Volume III - Socioeconomic and Environmental Assessments, was released for a 30-day public review and comment period on May 24, 1993. In response to comments received regarding the Draft EA, some components of the proposed project were modified. Subsequently, a Revised Draft EA was prepared and re-circulated for an additional public review and comment period of 45 days on July 22, 1993 The SCAQMD concluded that the changes in the Revised Draft EA did not alter the significance determination for any environmental impact areas analyzed in the May 1993 version of the Draft EA. After circulation of the Revised Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board at its hearing in October 1993.

Notice of Preparation/Initial Study of Draft Environmental Assessment for the Proposed Adoption of Regulation XX - RECLAIM; October 1992: The NOP/IS of a Draft EA for the proposed adoption of the NOx and SOx RECLAIM program was released for a 30-day public review and comment period on October 23, 1992. The NOP/IS identified “air quality,” “energy,” and “hazards and hazardous materials” as the key areas that may be adversely affected by the proposed project.

1.3 INTENDED USES OF THIS DOCUMENT

In general, a CEQA document is an informational document that informs a public agency's decision-makers and the public generally of potentially significant adverse environmental effects of a project, identifies possible ways to avoid or minimize the significant effects, and describes reasonable alternatives to the project (CEQA Guidelines §15121). A public agency's decision-makers must consider the information in a CEQA document prior to making a decision on the project. Accordingly, this ~~Draft~~ Final PEA is intended to: a) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental effects of the proposed project; and, b) be used as a tool by the SCAQMD Governing Board to facilitate decision making on the proposed project.

Additionally, CEQA Guidelines §15124 (d)(1) requires a public agency to identify the following specific types of intended uses of a CEQA document:

1. A list of the agencies that are expected to use the PEA in their decision-making;
2. A list of permits and other approvals required to implement the project; and,
3. A list of related environmental review and consultation requirements required by federal, state, or local laws, regulations, or policies.

There are no permits or other approvals required to implement the project. Moreover, the project is not subject to any other related environmental review or consultation requirements.

However, if an affected facility chooses to install new equipment or modify existing equipment, then SCAQMD permits, as well as other agency permits or other approvals depending on the physical changes being proposed, may also be required. To the extent that local public agencies, such as cities, county planning commissions, et cetera, are responsible for making land use and planning decisions related to projects proposed as a result of implementing the proposed project, they could possibly rely on this PEA during their decision-making process. Similarly, other single purpose public agencies approving projects at facilities complying with the proposed project may rely on this PEA. If the applicable lead agency finds that no new effects could occur, or no new mitigation measures would be required, the lead agency can approve the activity as being within the scope of the project covered by the PEA and no new environmental document would be required (CEQA Guidelines §15168 (c)(2)). If there are proposed activities that would have effects that were not examined in the PEA, then depending on the types of activities proposed by the affected facility and where the project is located, the appropriate lead agency would need to prepare an additional CEQA document to analyze the additional effects.

1.4 AREAS OF CONTROVERSY

CEQA Guidelines §15123 (b)(2) requires a public agency to identify the areas of controversy in the CEQA document, including issues raised by agencies and the public. Over the course of developing the proposed project, the predominant concerns expressed by representatives of industry and environmental groups, either in public meetings or in written comments, regarding the proposed project are highlighted in Table 1-1.

Table 1-1
Areas of Controversy

	Area of Controversy	Topics Raised by the Public	SCAQMD Evaluation
1.	Amount of proposed NOx shave and availability of RTCs	Industry representatives expressed concern that reducing the available NOx RTCs by the proposed amount would have severe impacts on the NOx RECLAIM program because there will not be enough NOx RTCs in the market.	The staff analysis shows that after the proposed shave is imposed, there will be sufficient NOx RTCs available to maintain trading within the NOx RECLAIM program given foreseeable opportunities for emissions reductions. Furthermore, the proposed NOx shave provides for a compliance margin and the NOx program includes provisions for adjustments if the price of RTCs exceeds certain thresholds.
2.	Equity of proposed NOx shave	NOx reductions should be based on facility-specific and technology-specific data, or, as others have commented, should be applied evenly across the all facilities. Many facilities cannot reduce NOx further. Other facilities do not have equipment subject to BARCT.	The proposed shave is based on source categories for which additional NOx reductions can be achieved in a cost-effective manner. It recognizes 219 ~~210~~ facilities hold 10 percent of the 26.5 tpd of the available NOx RTCs, and that for these facilities, no NOx RTC shave is proposed because either no new BARCT (not cost effective and/or infeasible) was identified, or gains in emission reductions would be negligible, for the types of equipment and source categories.
3.	Results of the BARCT analysis	The SCAQMD's consultant's report assessing the staff BARCT analysis recommended alternate engineering assumptions in certain areas.	While staff believes the engineering assumptions in the staff BARCT analysis are appropriate, the difference in BARCT reductions attributable to the alternate engineering assumptions suggested by the consultant is relatively small. To account for this difference and to provide a compliance margin, staff is proposing a shave of 14 tpd, reduced from the initial BARCT result of 14.79 ~~14.85~~ tpd.

Table 1-1 (continued)
Areas of Controversy

	Area of Controversy	Topics Raised by the Public	SCAQMD Evaluation
4.	Equivalency with command-and-control	The NOx RTC shave BARCT reductions of 8.77 ~~8.79~~ should be applied to the total RTC holdings rather than to the actual emissions in order to maintain the viability of the market	The total shave amount of 14 tpd is applied to total RTCs holdings. Consistent with previous RECLAIM rule amendments, the California Health & Safety Code, and the purpose of the program, BARCT implementation seeks to reduce actual emissions rather than RTC holdings. This approach will result in approximately 8.77 ~~8.79~~ tons per day of BARCT reductions of actual NOx emissions attributable to installing and operating additional controls. Otherwise, actual emissions reductions of only about two tpd over the next seven years would be achieved.
5.	2012 AQMP Commitment in the State Implementation Plan (SIP)	The control measure CMB-01 in the 2012 AQMP committed only three to five tpd NOx emission reductions but this rule development is seeking a higher amount of NOx reductions beyond what was committed in the SIP.	The staff proposal is the result of a much more rigorous and in-depth analysis as compared to the analysis that supported control measure CMB-01. For a market-based incentive program, SCAQMD staff is required by the California Health and Safety Code to conduct periodic BARCT reassessments and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment. CMB-01 anticipated this BARCT assessment but could not predict the results of the assessment, and therefore made commitments for a more modest reduction. This staff proposal recommends a reasonably available 14 tpd of NOx RTC reductions, based on BARCT, as required by state law, and which are needed to help the Basin achieve the PM2.5 standards by 2019 and 2025 and the ozone standards by 2024 and 2032.

Table 1-1 (concluded)
Areas of Controversy

	Area of Controversy	Topics Raised by the Public	SCAQMD Evaluation
6.	Availability of RTCs for future power plant needs	There may not be enough available RTCs after the shave for power producers to provide a reliable supply of electricity over the short-term (e.g., during high demand events such as a heat wave) and over the long-term (e.g., increased use in electricity needed to power electric vehicles).	The staff proposal would establish a separate Regional NSR Holding ~~adjustment~~ A~~a~~ccount to hold RTCs for electricity generating facilities (EGFs) ~~power plants~~ to meet their NSR holding obligations. Many newer peaking plants are required to hold RTCs at the potential to emit level each year even though their actual emissions are far below this level. The holding ~~adjustment~~ account would relieve EGFs ~~power producing facilities~~ from the obligation of holding RTCs in order to meet the NSR holding requirements of Rule 2005. RTCs would still be required for the purpose of reconciling annual emissions. Furthermore, if the demand for power results in a severe shortage that would lead to the state Governor declaring a state of emergency, an EGF ~~power producing facility~~ would be able to access the holding ~~adjustment~~ account for non-tradable credits to offset annual emissions.

Pursuant to CEQA Guidelines §15131 (a), "Economic or social effects of a project shall not be treated as significant effects on the environment." CEQA Guidelines §15131 (b) states further, "Economic or social effects of a project may be used to determine the significance of physical changes caused by the project." Physical changes caused by the proposed project have been evaluated in Chapter 4 of this PEA. No direct or indirect physical changes resulting from economic or social effects have been identified as a result of implementing the proposed project.

Of the topics discussed to address the concerns raised relative to CEQA and the secondary impacts that would be associated with implementing the proposed project, to date, no other controversial issues were raised as a part of developing the proposed project.

1.5 EXECUTIVE SUMMARY

CEQA Guidelines §15123 requires a CEQA document to include a brief summary of the proposed actions and their consequences. In addition, areas of controversy including issues raised by the public must also be included in the executive summary (see preceding discussion). This ~~Draft~~ Final PEA consists of the following chapters: Chapter 1 – Executive Summary;

Chapter 2 – Project Description; Chapter 3 – Existing Setting, Chapter 4 – Potential Environmental Impacts and Mitigation Measures; Chapter 5 – Project Alternatives; Chapter 6 - Other CEQA Topics and various appendices. The following subsections briefly summarize the contents of each chapter.

Summary of Chapter 1 – Executive Summary

Chapter 1 includes a discussion of the legislative authority that allows the SCAQMD to amend and adopt air pollution control rules, identifies general CEQA requirements and the intended uses of this CEQA document, and summarizes the remaining chapters that comprise this ~~Draft~~ Final PEA.

Summary of Chapter 2 - Project Description

To comply with the requirements in HSC §§40440~~ and 39616~~[5], SCAQMD staff conducted a BARCT assessment of the NOx RECLAIM program which resulted in adjusting BARCT levels for both equipment and source categories in the refinery and non-refinery sectors. For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters rated great than 40 mmBTU/hr, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal heat treating furnaces rated great than 150 mmBTU/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for 30 electricity generating facilities (EGFs)~~power plants~~. Overall, a total of 14 tpd of NOx RTC reductions from the current 2015 RTC holdings of 26.5 tpd is proposed to be implemented over a seven-year period from 2016 to 2022.

For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will be reduced from the allocations of 56 ~~65~~ facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 219 ~~210~~ facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified for the types of equipment and source categories at these facilities. By following this approach, the shave is distributed as follows:

- ~~67~~66% shave for 9 refineries and investors (treated as one facility)
- ~~47~~49% shave for 21 ~~30 power plants~~ EGFs
- ~~47~~49% shave for 26 non-major facilities
- 0% shave for 219 ~~210~~ remaining facilities

In addition, the overall NOx RTC reductions of 14 tpd are expected to be achieved incrementally from 2016 to 2022, according to the following implementation schedule:

- 2016 – 4 tons per day
- 2018 – 2 tons per day
- 2019 – 2 tons per day
- 2020 – 2 tons per day

[5] The reference to Health and Safety Code §39616 has been deleted because it does not require a BARCT analysis. The RECLAIM program proposed here satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so.

- 2021 – 2 tons per day
- 2022 – 2 tons per day

To incorporate the proposed NOx RTC shave and implementation schedule, amendments to the NOx RECLAIM regulation are proposed to establish procedures and criteria for reducing NOx RECLAIM RTCs and NOx RTC adjustment factors for year 2016. The proposed amendments contain the following key elements:

- Amend Rule 2001 – Applicability, to allow the owner or operator of an EGF to opt out of the NOx RECLAIM program.
- Amend Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to establish procedures and criteria for reducing NOx RTCs and NOx RTC adjustment factors for year 2016 and later.
- Amend Rule 2002 to add new BARCT emission factors ending in 2021 for an assortment of equipment/process categories.
- Amend Rule 2002 to change the maximum $15,000 per ton price trigger to $22,500 per ton (discrete credits, 12-month rolling average) and add a maximum trigger level of $35,000 per ton (discrete credits, 3-month rolling average).
- Amend Rule 2002 to allow new EGFs: 1) the use of the Regional NSR Holding Account for their New Source Review holding requirement; and, 2) access to this account during a Governor's declared state of emergency.
- Amend Rule 2002 to delete the provisions pertaining to RTC Reductions Exemptions.
- Amend Rule 2002 to add provisions to address the retirement of RTCs from complete facility closure or equipment shutdowns.
- Amend Rule 2005 – New Source Review for RECLAIM, to ~~clarify the criteria for how Adjustment~~ establish a Regional NSR Holding Account for EGF New Source Review holding requirements and set criteria for the use of those RTCs ~~are treated when conducting a New Source Review analysis for RECLAIM facilities~~ in the event the Governor declares a state of emergency for power generation.
- Amend Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures) to allow RECLAIM Facility Permit Holders of equipment experiencing certain extenuating circumstances to postpone Relative Accuracy Test Audits (RATAs).
- Amend Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures) to allow RECLAIM Facility Permit Holders of equipment experiencing certain extenuating circumstances to postpone RATAs.
- Make administrative and other minor changes such as correcting typographical errors as well as clarifying and updating the rule and rule protocol language for consistency.

Other minor changes are proposed for clarity and consistency throughout the proposed amended regulation. Instructions for obtaining the latest version ~~A copy~~ of the proposed amended Rules (PAR) 2001, 2002 and 2005 can be found in Appendices A1, A2, and B, respectively, of this ~~Draft~~ Final PEA and instructions for obtaining the latest version ~~. A copy~~ of the proposed amended protocols for Rules 2011 and 2012 can be found in Appendices C and D, respectively.

Summary of Chapter 3 - Existing Setting
Pursuant to the CEQA Guidelines §15125, Chapter 3 – Existing Setting, includes descriptions of those environmental areas that could be adversely affected by the proposed project as identified in the NOP/IS (Appendix F). The following environmental areas identified in the NOP/IS that could potentially be adversely affected by implementing the proposed project are: aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic. As such, Chapter 3 contains subchapters devoted to describing the existing setting for each environmental topic area evaluated in the PEA.

Summary of Chapter 4 - Environmental Impacts
CEQA Guidelines §15126 (a) requires that a CEQA document shall identify and focus on the "significant environmental effects of the proposed project." Direct and indirect significant effects of the project on the environment shall be clearly identified and described, giving due consideration to both the short-term and long-term effects.

The NOP/IS identified and described those environmental topics where the proposed project could cause significant adverse environmental impacts (e.g., aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic). The type of emission reduction projects that may be undertaken to comply with the proposed project is the main focus of the analysis in this PEA. There are multiple source categories with multiple approaches to reducing NOx emissions. With so many possibilities or permutations of how operators of NOx RECLAIM facilities could achieve actual NOx reductions, there is no way to predict what each facility operator will do. For this reason, the proposed project analysis has been crafted to illustrate the worst-case effects of applying the various NOx control technologies along with demonstrating the flexibility that is provided by the RECLAIM program to facility operators when it comes to choosing the methods for reducing NOx emissions. The analysis focuses on the installation and operation of NOx control technologies for the various equipment types/source categories.

The following subsections briefly summarize the analysis of potential adverse environmental impacts from the implementation of the proposed project. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse impacts for the following environmental topics.

Aesthetics
Physical modifications may result as part of implementing the proposed project and will vary depending on the equipment source category/process. The analysis in this CEQA document is based on the assumption that new air pollution control equipment is

expected to be installed and existing air pollution control equipment is expected to be modified as part of implementing the proposed project. Aesthetic impacts associated with the installation of new or the modification of existing NOx control, were identified in the NOP/IS to be potentially significant and, as such, are evaluated in this PEA.

Implementation of the proposed project is expected to result in construction activities at some or all of the affected facilities, which are complex industrial facilities. Due to the large size profiles of the affected equipment, the construction activities associated with installing control equipment are expected to require the use of heavy-duty construction equipment, such as cranes, which may temporarily change the skyline of the affected facilities, depending on where they are located within each facility's property. However, because each affected facility is located in a heavy industrial area, the construction equipment is not expected to be substantially discernable from what would be needed for routine operations and maintenance activities. For these reasons, the construction activities are expected to blend in with the existing industrial environment and thus, are not expected to affect the visual continuity of the surrounding areas.

In addition, for any installation of a WGS, operational aesthetic impacts resulting from a substantial visible steam (water vapor) plume that would emanate from the WGS stack were evaluated in this PEA. The analysis will show that if any WGS is installed as part of the proposed project at any of the affected facilities, the steam plume, though visible, is not expected to significantly adversely affect the visual continuity of the surrounding area of each affected facility because no scenic highways or corridors exist within the areas of the refineries, the coke calciner, the sulfuric acid plants and the glass melting plant. Further, the visual continuity of the surrounding area is not expected to be adversely impacted because each WGS, if constructed, will be built within the confines of industrial areas and would be visually consistent with the profiles of the existing affected facilities. Thus, even if each WGS could be visible, depending on the location within each property boundary, the aesthetic significance criteria would not be exceeded. For these reasons, less than significant aesthetics impacts during operation are expected from the proposed project.

Overall, the aesthetics impacts were determined to be less than significant during both construction and operation for the proposed project.

Air Quality and Greenhouse Gases

The proposed project is expected to result in a total of 14 tpd of NOx RTC reductions from the current RTC holdings of 26.5 tpd, to be implemented over a seven-year period from 2016 to 2022. For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will affect 56 ~~65~~ facilities plus the investors, who collectively hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 219 ~~210~~ facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified for the types of equipment and source categories at these facilities. By following this approach, the shave of NOx RTC holdings is distributed as follows:

- 66 ~~67~~% shave for 9 refineries and investors (treated as one facility)
- 49 ~~47~~% shave for 21 electrical generating facilities (EGFs) ~~30 power plants~~

- 49 ~~47~~% shave for 26 non-major facilities
- 0% shave for 219 ~~210~~ remaining facilities

SCAQMD staff has conducted a BARCT analysis for all 275 facilities and of these, 21 out of 30 EGFs ~~power producing facilities~~ were shown to operate at current BARCT or BACT levels. For 224 non-power plant facilities plus 9 EGFs for a total of 233 facilities, either no new BARCT was identified or the installation of control equipment was determined to not be cost-effective. Further, only 35 ~~44~~ facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact. In addition, the sale and/or purchase of RTCs by investors (treated as one facility) will also have no environmental impact.

To reduce NOx from the remaining 21 facilities (e.g., 275 ~~–~~ – 21 EGFs (with shave) ~~30 power producers~~ - 224 non-power plant facilities – 9 EGFs (without shave) = 21) which are either major or large sources of NOx for which new BARCT has been identified, the BARCT analysis found that it would be both feasible and cost-effective for facility operators to install new control equipment or modify existing control equipment at 20 facilities with 11 facilities belonging to the non-refinery sector and 9 facilities belonging to the refinery sector.

As a result, operators of these 20 facilities may choose to modify existing equipment by retrofitting with air pollution control technologies in order to comply with the shave of NOx RTCs. The physical changes involved that may occur as a result of implementing the proposed project focus on the installation of new or the modification of existing control equipment on the following types of equipment and processes: 1) fluid catalytic cracking units; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. Table 1-2 summarizes the potential NOx control technologies that may be considered as part of implementing the proposed project.

Table 1-2
Potential NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Potential NOx Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	SCR LoTOx™ with WGS LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	SCR
Refinery	Refinery Gas Turbines	SCR
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	LoTOx™ with WGSs SCR
Refinery	Petroleum Coke Calciner	LoTOx™ with WGS UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	SCR UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	SCR UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	SCR
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	SCRs

Construction activities associated with installing or modifying existing air pollution control equipment are expected and have the potential to generate significant adverse air quality impacts for criteria pollutants. In addition, operational activities due to periodic truck trips such as the delivery of supplies to support the operations of the various control technologies and the removal of waste from the control processes for disposal or recycling are also expected and have the potential to generate significant adverse air quality impacts for NOx and greenhouse gases (GHGs).

With regard to GHG emissions, the proposed project involves combustion processes which could generate GHG emissions such as CO2, CH4, and N2O. However, the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs or PFCs. Implementing the proposed project is expected to increase GHG emissions that exceed the SCAQMD's GHG significance threshold for industrial sources. In addition, implementing the proposed project is expected to generate significant adverse cumulative GHG air quality impacts.

Energy

Implementation of the proposed project is expected to increase the amount of energy needed to both construct and operate the new and modified air pollution control devices. During construction, increased use of diesel fuel and gasoline are expected from on- and off-road vehicle and equipment use. Operational activities of the new and modified air pollution control equipment are expected to result in an overall increase in electricity as well as an increased use of diesel fuel associated with supply delivery trips and waste removal trips as part of day-to-day operations. Despite the potential increases in energy use overall as part of implementing the proposed project, the increases are not expected to exceed the energy significance thresholds.

Hazards and Hazardous Materials

Implementation of the proposed project may alter the hazards and hazardous materials associated with the existing facilities affected by the proposed project. Air pollution control equipment and related devices are expected to be installed or modified at affected facilities such that their operations may increase the quantity of materials used in the control equipment, some of which are hazardous. For example, the proposed project could result in the increased use of hazardous materials such as ammonia and sodium hydroxide and non-hazardous materials such as soda ash and hydrated lime. Thus, the routine transport of hazardous materials, use, and disposal of hazardous materials may increase as a result of the proposed project. The hazards analysis focuses on the materials used that may be hazardous. The analysis concluded that the proposed project is expected to generate significant adverse hazards and hazardous materials impacts for ammonia deliveries and less than significant hazards and hazardous materials impacts for ammonia use and storage. For the substances other than ammonia that were identified as hazardous, the proposed project is expected to generate less than significant hazards and hazardous materials impacts.

Hydrology and Water Quality

Implementation of the proposed project may cause hydrology and water quality impacts associated with the existing facilities affected by the proposed project. Specifically, the installation of WGS technology involves an increased demand for water and an increased amount of wastewater discharge. None of the other NOx control technologies contemplated by the proposed project are expected to create hydrology and water quality impacts.

For water demand, there are three significance thresholds based on whether: 1) the total water demand of the proposed project is less than five million gallons per day; 2) the existing water supply has the capacity to meet the increased demands of the proposed project; and, 3) the potable water demand is less than 262,820 gallons per day. The analysis shows that the increased potential demand for total water that may result from implementing the proposed project either during construction or operation is not expected to exceed the significance threshold of five million gallons of total water demand per day.

The analysis shows a potential increase in water use of 353,724 gallons per day for all 20 facilities conducting hydrotesting activities on a peak day. The amount of water that may be needed to conduct hydrotesting on a peak day is greater than the SCAQMD's significance threshold of 262,820 gallons per day of potable water. Thus, the amount of potable water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is potentially significant.

The analysis also shows a potential increase in water use for facilities that utilize WGS technology would be a range, from 553,499 gallons per day to 558,978 ~~602,1854~~ gallons per day, which exceeds the SCAQMD's significance threshold of 262,820 gallons per day of potable water. Thus, the amount of potable water that may be used on a daily basis for operating NOx control equipment (e.g., WGSs) is also potentially significant.

Because the entire state of California is in the midst of a severe drought and because construction of WGS technology may not occur for at least another year or more, it was ~~is~~ not clear at the time of release of the Draft PEA if the local water suppliers would ~~will~~ have enough potable water to meet the increased demands to supply the WGSs in the future. Subsequently, SCAQMD staff has been able to verify that projected water deliveries of potable water and recycled water to the affected facilities sources will be able to supply the potential water demand needs of the proposed project. While the use of recycled water may be able to offset some of the potable water demands from the proposed project, not all of the facilities whose storage tanks need hydrotesting and whose operations are potential candidates for WGS technology, have current access to recycled water. For this reason, the analysis conservatively concludes that the amount of water that may be needed to hydrotest storage tanks and to operate WGS technology may create significant adverse hydrology (water demand) impacts.

Relative to water quality, the analysis will also show that implementing the proposed project may increase the amount of wastewater discharged from certain affected facilities. However, the potential increases will not cause a permit revision to any affected facility's wastewater permit and as such, will not exceed the wastewater significance threshold. For this reason, the wastewater impacts from the proposed project are expected to be less than significant.

Solid and Hazardous Waste

Construction activities associated with installing NOx control equipment such as demolition and site preparation/grading/excavating could generate solid waste as result of implementing the proposed project. However, the amount of debris generated during construction at 20 facilities would not be expected to exceed the designated capacity of local landfills. For this reason, the construction impacts of the proposed project on waste treatment/disposal facilities were concluded to be less than significant. Solid waste may also be generated from the operation of the new NOx air pollution control equipment at both the refinery and non-refinery facilities. Further, it is possible that some, if not all, of the 20 affected facilities will address any increase in waste through their existing waste minimization plans. For example, some of the affected facilities in both the refinery and non-refinery sectors currently have existing catalyst-based operations and the spent catalysts are either regenerated, reclaimed or recycled, in lieu of disposal, and this practice would be expected to continue. The overall impacts of the proposed project on waste treatment/disposal facilities due to solid waste that may be generated from both refinery and non-refinery facilities during construction and operation were concluded to be less than significant.

Transportation and Traffic

Implementation of the proposed project may cause adverse transportation and traffic impacts associated with the existing facilities affected by the proposed project. Specifically, construction-based traffic associated with the installation of NOx control technology is expected from construction workers, delivery trucks and haul trucks. During operation of the proposed project, regular deliveries and waste disposal activities are also expected to increase at each of the affected facilities. Despite the increases, the analysis shows that the transportation and traffic impacts, though adverse, are less than significant for the proposed project during both construction and operation.

Potential Environmental Impacts Found Not To Be Significant

The NOP/IS for the proposed project included an environmental checklist of approximately 17 environmental topics to be evaluated for potential adverse impacts from a proposed project. Review of the proposed project at the NOP/IS stage identified seven topics (e.g., aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic), for further review in the ~~Draft~~ Final PEA. Where the NOP/IS concluded that the project would have no significant direct or indirect adverse effects on the remaining environmental topics, of the comments received on the NOP/IS or at the public meetings, none of the comments changed this conclusion. The screening analysis concluded that the following environmental areas would not be significantly adversely affected by the proposed project:

- agriculture and forestry resources
- biological resources
- cultural resources
- geology and soils
- land use and planning
- mineral resources
- noise
- population and housing
- public services
- recreation

The NOP/IS for the proposed project was circulated for a 57-day review and comment period from December 5, 2014 to January 30, 2015. At the time the NOP/IS was circulated, the environmental checklist did not include tribal cultural resources as a topic to be evaluated under Cultural Resources as part of a CEQA document. However, the requirements of California Assembly Bill (AB 52) went into effect on July 1, 2015. AB 52 is promulgated in Public Resources Code §21080.3.1 (d) and requires a formal notification to all California Native American Tribes about lead agency projects that would require the preparation of a CEQA document. While the Office of Planning and Rule (OPR) has until July 1, 2016 to finalize the implementation guidance for this requirement, the SCAQMD is required to comply with AB 52 in the interim.

Subsequent to release of the NOP/IS, modifications were made to the environmental checklist (e.g., a new question was added), significance criteria, and discussion of Cultural Resources impacts in response to the requirements in AB 52 to consider the proposed project's potential effects on Cultural Native American Tribe resources. Although the NOP/IS did not include a preliminary analysis of tribal cultural resources, to make the analysis of environmental impacts consistent with the recent changes to the environmental checklist, a discussion of impacts from the proposed project relative to tribal cultural resources has been included in this subchapter of the ~~Draft~~ Final PEA. No significant impacts on tribal cultural resources were identified. Thus, even with the additional information pertaining to tribal cultural resources, the overall conclusion of "No Impact" for this topic area remains unchanged.

Other CEQA Topics

CEQA documents are required to address the potential for irreversible environmental changes, growth-inducing impacts and inconsistencies with regional plans. The analysis confirms that proposed project would not result in irreversible environmental changes or the irretrievable commitment of resources, foster economic or population growth or the construction of additional housing, or be inconsistent with regional plans.

Summary Chapter 5 - Alternatives

The proposed project and five alternatives to the proposed project are summarized in Table 1-3: Proposed Project (Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities), Alternative 1 (Across the Board), Alternative 2 (Most Stringent), Alternative 3 (Industry Approach), Alternative 4 (No Project), and, Alternative 5 (Weighted by BARCT Reduction Contribution for all facilities and investors). Pursuant to the requirements in CEQA Guidelines §15126.6 (b) to mitigate or avoid the significant effects that a project may have on the environment, a comparison of the potentially significant adverse impacts from each of the project alternatives for the individual rule components that comprise the proposed project is provided in Table 1-4. In addition to the topic of the topics of air quality and GHGs, the alternatives comparison in Table 1-4 addresses the topics of aesthetics, energy, hazards and hazardous materials, hydrology and water quality, solid and hazardous waste, and transportation and traffic. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse environmental impacts for the proposed project as summarized in Table 1-4.

Aside from these topics, no other potentially significant adverse impacts were identified for the proposed project or any of the project alternatives. The proposed project is considered to provide the best balance between emission reductions and the adverse environmental impacts due to construction and operation activities while meeting the objectives of the project. Therefore, the proposed project is preferred over the project alternatives.

Table 1-3
Summary of Proposed Project & Alternatives

Components of Proposed Project		Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	NOx Reduction Potential *(tons/day)*	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	NOx Reduction Potential *(tons/day)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	NOx Reduction Potential *(tons/day)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	NOx Reduction Potential *(tons/day)*
Proposed NOx RTC "Shave"			**14.00**		**14.00**		**15.87**		**8.00**
Basic Equipment	**BARCT**								
FCCU	SCR or LoTOx™ with WGS	2 ppmv NOx at 3% O2	0.43	Same as proposed project	0.43	Same as proposed project	0.43	Same as proposed project	0.43
Refinery Boilers/ Heaters	SCR	2 ppmv NOx, or 0.002 lb NOx/mmBTU	0.94 ~~0.96~~	Same as proposed project	0.94 ~~0.96~~	Same as proposed project	0.94 ~~0.96~~	Same as proposed project	0.94 ~~0.96~~
Refinery Gas Turbines	SCR or SCR Catalyst	2 ppmv NOx at 15% O2	4.14	Same as proposed project	4.14	Same as proposed project	4.14	Same as proposed project	4.14
SRU/TGU	LoTOx™ with WGS or SCR	2 ppmv NOx at 3% O2, or 95% reduction	0.32	Same as proposed project	0.32	Same as proposed project	0.32	Same as proposed project	0.32
Coke Calciner	LoTOx™ with WGS or Ultracat DGS	10 ppmv at 3% O2	0.17	Same as proposed project	0.17	Same as proposed project	0.17	Same as proposed project	0.17
Glass Melting Furnace	SCR or Ultracat DGS	80% reduction, or 0.024 lb NOx per ton glass produced	0.24	Same as proposed project	0.24	Same as proposed project	0.24	Same as proposed project	0.24
Sodium Silicate Furnace	SCR or Ultracat DGS (without dry sorbent)	80% reduction, or 1.28 lb NOx per ton of glass pulled	0.09	Same as proposed project	0.09	Same as proposed project	0.09	Same as proposed project	0.09
Metal Heat Treating Furnace	SCR	9 ppmv at 3% O2, or 0.011 lb NOx/mmBTU	0.56	Same as proposed project	0.56	Same as proposed project	0.56	Same as proposed project	0.56
ICEs (Non-Refinery/Non-Power Plant)	SCR	11 ppmv NOx at 15% O2, 0.041 lb NOx/mmBTU, or 43.05 lb NOx/MMcf	0.84	Same as proposed project	0.84	Same as proposed project	0.84	Same as proposed project	0.84
Gas Turbines (Non-Refinery/ Non-Power Plant)	SCR	2 ppmv NOx at 15% O2	1.04	Same as proposed project	1.04	Same as proposed project	1.04	Same as proposed project	1.04
Potential NOx Emission Reductions (BARCT)			**8.77 ~~8.79~~**		**8.77 ~~8.79~~**		**8.77 ~~8.79~~**		**8.77 ~~8.79~~**
NOx RTCs Needed to Fulfill Shave Post-BARCT			**5.23 ~~5.21~~**		**5.23 ~~5.21~~**		**7.10 ~~7.08~~**		**0**

Key: SCR = Selective Catalytic Reduction; WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber
ppmv = parts per million by volume; mmBTU = million British Thermal Units; MMcf = million cubic feet

Table 1-3 (concluded)
Summary of Proposed Project & Alternatives

Components of Proposed Project		**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**NOx Reduction Potential** *(tons/day)*	**Alternative 4: No Project**	**NOx Reduction Potential** *(tons/day)*	**Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors**	**NOx Reduction Potential** *(tons/day)*
Proposed NOx RTC "Shave"			**14.00**		**0**		**14.00**
Basic Equipment	**BARCT**						
FCCU	SCR or LoTOx™ with WGS	2 ppmv NOx at 3% O2	0.43	No NOx limit	0	Same as proposed project	0.43
Refinery Boilers/ Heaters	SCR	2 ppmv NOx, or 0.002 lb NOx/mmBTU	0.94 ~~0.96~~	No NOx limit	0	Same as proposed project	0.94 ~~0.96~~
Refinery Gas Turbines	SCR or SCR Catalyst	2 ppmv NOx at 15% O2	4.14	No NOx limit	0	Same as proposed project	4.14
SRU/TGU	LoTOx™ with WGS	2 ppmv NOx at 3% O2, or 95% reduction	0.32	No NOx limit	0	Same as proposed project	0.32
Coke Calciner	LoTOx™ with WGS or Ultracat DGS	10 ppmv at 3% O2	0.17	No NOx limit	0	Same as proposed project	0.17
Glass Melting Furnace	SCR or Ultracat DGS	80% reduction, or 0.024 lb NOx per ton glass produced	0.24	No NOx limit	0	Same as proposed project	0.24
Sodium Silicate Furnace	SCR or Ultracat DGS (without dry sorbent)	80% reduction, or 1.28 lb NOx per ton of glass pulled	0.09	No NOx limit	0	Same as proposed project	0.09
Metal Heat Treating Furnace	SCR	9 ppmv at 3% O2, or 0.011 lb NOx/mmBTU	0.56	No NOx limit	0	Same as proposed project	0.56
ICEs (Non-Refinery/Non-Power Plant)	SCR	11 ppmv NOx at 15% O2, 0.041 lb NOx/mmBTU, or 43.05 lb NOx/MMcf	0.84	No NOx limit	0	Same as proposed project	0.84
Gas Turbines (Non-Refinery/ Non-Power Plant)	SCR	2 ppmv NOx at 15% O2	1.04	No NOx limit	0	Same as proposed project	1.04
Potential NOx Emission Reductions			**8.77~~8.79~~**		**0**		**8.77 ~~8.79~~**
NOx RTCs Needed to Fulfill Shave Post-BARCT			**5.23 ~~5.21~~**		**0**		**5.23 ~~5.21~~**

Key: WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber
Key: SCR = Selective Catalytic Reduction; WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber
ppmv = parts per million by volume; mmBTU = million British Thermal Units; MMcf = million cubic feet

Table 1-4
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Aesthetics	Visible steam plumes and new, tall stacks from installing/operating up to 8 WGSs at 7 facilities as follows: FCCU: 2 WGSs SRU/TGU: 5 WGSs Coke Calciner: 1 WGS	Same as proposed project	Same as proposed project, but if facility operators install additional WGSs beyond what is analyzed for the proposed project to obtain a compliance margin, then additional steam plumes and tall stacks could occur.	Less than proposed project	No installation of WGSs (e.g., no visible steam plumes and no new, tall stacks) expected	Same as proposed project
Aesthetics Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project, but potentially more adverse aesthetics impacts if facility operators install additional WGSs beyond what is analyzed for the proposed project)	Less than significant (less than proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)
Air Quality & GHGs	• Reduces total operational NOx emissions by 8.77 ~~8.79~~ tpd • Reduces total NOx RTC holdings by 14.0 tpd • Unused NOx RTCs to be applied to shave is 5.23 ~~5.21~~ tpd • Increases total GHGs by: - 41,785 MT/yr without mitigation; & - 41,100 MT/yr with mitigation • Increases operational use of NaOH (a TAC) by 5.84 tpd	Same as proposed project	• Reduces total operational NOx emissions by 8.77 ~~8.79~~ tpd • Reduces total NOx RTC holdings by 15.87 tpd • Unused NOx RTCs to be applied to shave is 7.10 ~~7.08~~ tpd • Increases total GHGs by: - 41,785 MT/yr without mitigation; & - 41,100 MT/yr with mitigation • Increases operational use of NaOH (a TAC) by 5.84 tpd	• Less operational NOx reductions than proposed project but not quantifiable • Reduces total NOx RTC holdings by 8.00 tpd • Less increases to GHGs than proposed project, but not quantifiable before or after mitigation • Less increases in operational use of NaOH (a TAC) but not quantifiable	• No decreases in total operational NOx emissions. • No increases in construction emissions for any pollutant.	Same as proposed project

Table 1-4 (continued)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**Alternative 1: Across the Board Shave *(All facilities reduce 53%)***	**Alternative 2: Most Stringent Shave *(All facilities reduce 60%)***	**Alternative 3: Industry Approach *(All facilities reduce 33%)***	**Alternative 4: No Project**	**Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors**
Air Quality & GHGs (concluded)	• Increases operational use of NH3 (a TAC) by 39.5 tpd • Increases peak daily operation emissions as follows: VOC: 17 lb/day CO: 75 lb/day NOx: 190 lb/day* PM10: 22 lb/day PM2.5: 19 lb/day • Increases peak daily emissions for construction in same year as follows: VOC: 429 lb/day CO: 2,745 lb/day NOx: 1,656 lb/day SOx: 3 lb/day PM10: 1,758 lb/day without mitigation; & 853 ~~1,009~~ lb/day with mitigation PM2.5: 883 lb/day without mitigation; & 430 ~~508~~ lb/day with mitigation	Same as proposed project	• Increases operational use of NH3 (a TAC) by 39.5 tpd Increases peak daily operation emissions as follows: VOC: 17 lb/day CO: 75 lb/day NOx: 190 lb/day* PM10: 22 lb/day PM2.5: 19 lb/day • Increases peak daily emissions for construction in same year as follows: VOC: 429 lb/day CO: 2,745 lb/day NOx: 1,656 lb/day SOx: 3 lb/day PM10: 1,758 lb/day without mitigation; & 853 ~~1,009~~ lb/day with mitigation PM2.5: 883 lb/day without mitigation; & 430 ~~508~~ lb/day with mitigation • If additional controls are installed beyond the proposed project for a compliance margin, more emission benefits as well as increased emissions impacts could occur.	• Less increases in operational use of NH3 (a TAC) but not quantifiable • Less increases in peak daily operation emissions but not quantifiable • Less increases in peak daily emissions for construction but not quantifiable with or without mitigation	• No decreases in total operational NOx emissions • No increases in construction emissions for any pollutant.	Same as proposed project

* The potential increases in NOx operational emissions are more than offset by the overall project reductions.

Table 1-4 (continued)

Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**Alternative 1: Across the Board Shave *(All facilities reduce 53%)***	**Alternative 2: Most Stringent Shave *(All facilities reduce 60%)***	**Alternative 3: Industry Approach *(All facilities reduce 33%)***	**Alternative 4: No Project**	**Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors**
Air Quality & GHG Impacts Significant?	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd. • Less than significant for VOC, CO, PM10 and PM2.5 during operation • Significant for GHGs • Less than significant for TACs use (NaOH and NH3) during operation • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd (same as proposed project) • Less than significant for VOC, CO, PM10 and PM2.5 during operation (same as proposed project) • Significant for GHGs (same as proposed project) • Less than significant for TACs use (NaOH and NH3) during operation (same as proposed project) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (same as proposed project)	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd (same as proposed project) • Less than significant for VOC, CO, PM10 and PM2.5 during operation (same as proposed project) • Significant for GHGs (same as proposed project) • Less than significant for TACs use (NaOH and NH3) during operation (same as proposed project) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (same as proposed project) • If additional controls are installed beyond the proposed project for a compliance margin, more emission benefits and increased emissions could occur.	• Less than significant; achieves net NOx emission reductions during operation (less reductions than the proposed project but not quantifiable) • Less than significant increases in VOC, CO, PM10 and PM2.5 during operation (less than the proposed project but not quantifiable) • Significant for GHGs, (less than proposed project but not quantifiable) • Less than significant for TACs use (NaOH and NH3) during operation (less than the proposed project but not quantifiable) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (less than proposed project but not quantifiable)	• No Impact - Not Significant • Does not achieve required AQMP NOx emission reductions during operation • Does not comply with BARCT assessment requirements per Health and Safety Code	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd (same as proposed project) • Less than significant for VOC, CO, PM10 and PM2.5 during operation (same as proposed project) • Significant for GHGs(same as proposed project) • Less than significant for TACs use (NaOH and NH3) during operation (same as proposed project) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (same as proposed project)

Table 1-4 (continued)

Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Energy	• During construction: -Increased use of diesel by 15,855 gal/day -Increase use of gasoline by 5,422 gal/day • During operation: -Increased use of electricity by 214 MWh/day -Increased use of diesel by 8,380 gal/day	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, increased energy use during construction and operation could occur	Less than the proposed project	No increases in energy uses during construction or operation	Same as proposed project
Energy Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased energy use than the proposed project could occur.)	Less than significant (less than the proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)
Hazards & Hazardous Materials	Increased use of 5.84 tons/day of NaOH and 39.5 tons/day of NH3 (both TACs) used during operation.	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional NaOH and NH3 may be needed.	Less than the proposed project	No change to existing hazards and hazardous materials used	Same as proposed project
Hazards & Hazardous Materials Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased use of NaOH and NH3 could occur.)	Less than significant	No Impact - Not Significant	Less than significant (same as proposed project)

Table 1-4 (continued)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Hydrology & Water Quality	• During construction: -Increased use of water for dust suppression by 12,501 gal/day -Increased use of water for hydrotesting by 353,724 gal/day • During operation -Increased use of potable water by 553,499 to 558,978 ~~602,814~~ gal/day (of which 512,603 up to 518,082 ~~204,047~~ gal/day could potentially be supplied by recycled water) -Increased generation of wastewater by 214,801 ~~236,719~~ gal/day.	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional water demand and increased wastewater generation may occur.	Less than the proposed project	No change to existing water demand or wastewater discharge	Same as proposed project
Hydrology & Water Quality Impacts Significant?	• Significant for water demand during hydrotesting (assuming entire demand is based on potable water) • Significant for water demand during operation (assuming entire demand is based on potable water) • Less than significant for water demand during construction • Less than significant for wastewater discharge during construction and operation	-Significant for water demand (same as proposed project) -Less than significant for wastewater discharge (same as proposed project)	-Significant for water demand (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased use of water during construction and operation may be needed) -Less than significant for wastewater discharge (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, then additional wastewater may be discharged	-Significant for water demand (less than proposed project) -Less than significant for wastewater discharge (less than proposed project)	No Impact - Not Significant	-Significant for water demand (same as proposed project) -Less than significant for wastewater discharge (same as proposed project)

Table 1-4 (concluded)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**Alternative 1: Across the Board Shave** ***(All facilities reduce 53%)***	**Alternative 2: Most Stringent Shave** ***(All facilities reduce 60%)***	**Alternative 3: Industry Approach** ***(All facilities reduce 33%)***	**Alternative 4: No Project**	**Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors**
Solid & Hazardous Waste	• During construction: -Increased generation of non-hazardous solid waste • During operation: -Increased generation of non-hazardous solid waste that can be recycled	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional solid waste may be generated.	Less than the proposed project	No change to existing disposal of solid & hazardous waste	Same as proposed project
Solid & Hazardous Waste Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased use of water during construction and operation may be needed)	Less than significant (less than the proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)
Transportation & Traffic	Overall peak increase in transportation and traffic of 485 trips per day during construction and 65 trips per day during operation.	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional daily trips during construction and operation may be needed.	Less than the proposed project	No change to existing transportation and traffic.	Same as proposed project
Transportation & Traffic Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional daily trips during construction and operation may be needed)	Less than significant (less than the proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)

Summary Chapter 6 - References
This chapter contains a list of the references and the organizations and persons consulted for the preparation of this PEA.

Summary Chapter 7 - Acronyms
This chapter contains a list of the acronyms that were used throughout the PEA and the corresponding definitions.

Appendix A1 - Proposed Amended Rule 2001 - Applicability
This appendix contains the instructions for accessing the latest version of the proposed amended rule language for PAR 2001.

Appendix A2 - Proposed Amended Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)
This appendix contains the instructions for accessing the latest version of the proposed amended rule language for PAR 2002.

Appendix B - Proposed Amended Rule 2005 - New Source Review For RECLAIM
This appendix contains the instructions for accessing the latest version of the proposed amended rule language for PAR 2005.

Appendix C - Proposed Amended Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
This appendix contains the instructions for accessing the latest version of the proposed amended protocol language for Rule 2011.

Appendix D - Proposed Amended Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
This appendix contains the instructions for accessing the latest version of the proposed amended protocol language for Rule 2012.

Appendix E - Construction and Operation Calculations
This appendix contains the assumption and calculations for construction and operation activities associated with the proposed project.

Appendix F - Notice of Preparation/Initial Study (NOP/IS) (Environmental Checklist)
This appendix contains the NOP/IS that was released for public review and comment from December 5, 2014 to January 30, 2015.

Appendix G - Comment Letters Received on the NOP/IS and Responses to the Comments
This appendix contains the comment letters received relative to the NOP/IS and the responses to individual comments.

Appendix H – CEQA Scoping Meeting Comments and Responses to the Comments
This appendix contains a summary of the CEQA-related comments made at the CEQA Scoping Meeting held on January 8, 2015 and the responses to individual comments.

Appendix I - Comment Letters Received on the Draft PEA and Responses to the Comments
This appendix contains the comment letters received relative to the Draft PEA and the responses to individual comments.

CHAPTER 2

PROJECT DESCRIPTION

Project Location

Project Background

Project Objectives

Project Description

Technology Overview

2.0 PROJECT LOCATION

The proposed amendments to Regulation XX would apply to equipment and processes operated at NOx RECLAIM facilities located throughout the entire SCAQMD jurisdiction. The SCAQMD has jurisdiction over an area of approximately 10,743 square miles, consisting of the four-county South Coast Air Basin (Basin) (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin (SSAB) and Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto mountains to the north and east. It includes all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of Riverside County and the SSAB that is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (see Figure 2-1).

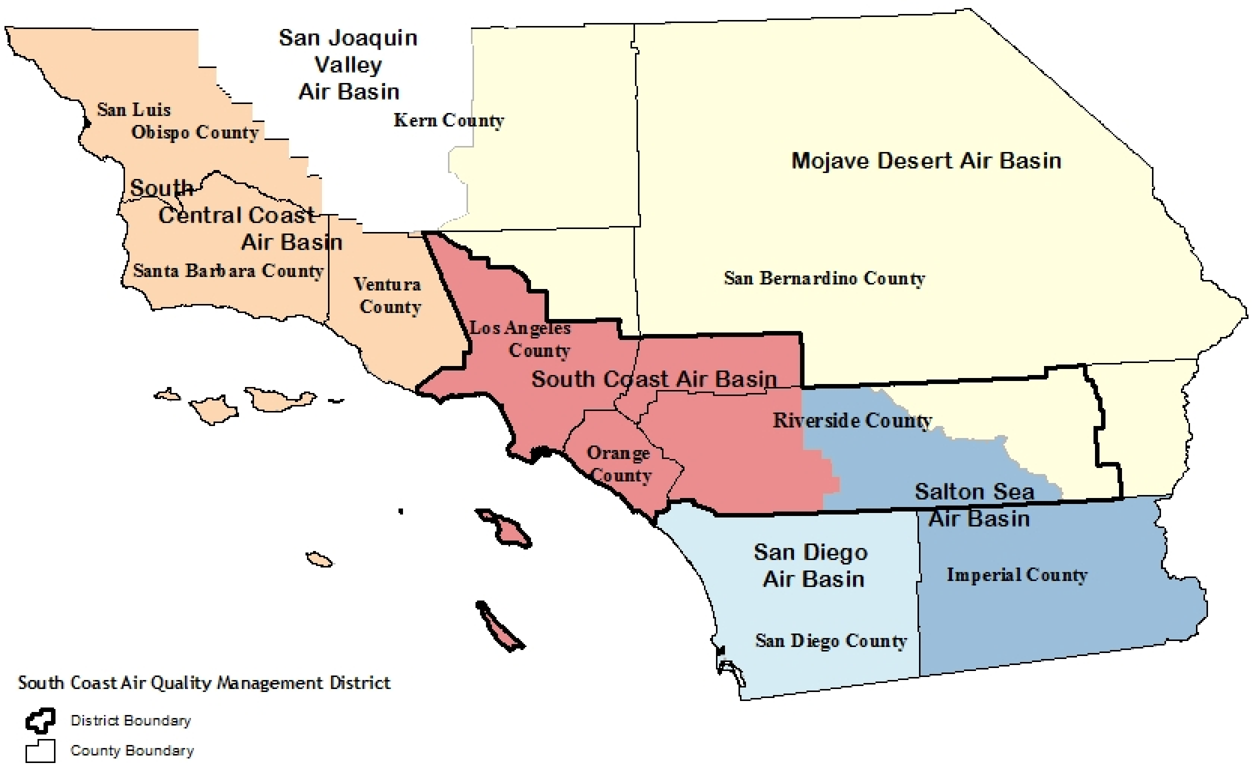

Figure 2-1: Southern California Air Basins

2.1 PROJECT BACKGROUND

On October 15, 1993, the SCAQMD Governing Board adopted Regulation XX, referred to herein as the RECLAIM program. Regulation XX is comprised of 15 rules which contain a declining market-based cap and trade mechanism to reduce NOx and SOx emissions from the largest stationary sources in the Basin and subsequently help meet air quality standards while providing facilities with the flexibility to seek the most cost-effective solution for achieving the required reductions. Instead of setting specific limits on each piece of equipment and each process that contributes to air pollution as is stipulated by traditional 'command-and-control' regulations, under the RECLAIM program each facility has a NOx and/or SOx annual emissions limit (allocation) and facility operators can decide what equipment, processes and materials they will use to reduce emissions to meet or go further below their annual emission limits. In lieu of reducing emissions, facility owners or operators may elect to use the trading market to purchase RTCs from other facilities that have reduced emissions below their annual target.

The portion of Regulation XX that focuses on reducing NOx emissions is referred to as "NOx RECLAIM" while the portion that focuses on reducing SOx emissions is referred to as "SOx RECLAIM." Regulation XX contains applicability requirements, NOx and SOx facility allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements for NOx and SOx sources located at RECLAIM facilities. The RECLAIM program started with 41 SOx facilities and 392 NOx facilities, but by the end of the 2005 compliance year, the program was populated with 33 SOx facilities and 304 NOx facilities. The population at the end of compliance year 2011 consists of 33 SOx facilities and 276 NOx facilities. The reduction in the number of facilities participating in the RECLAIM program since inception has been primarily due to facility shutdowns and/or consolidations. By the end of compliance year 2013, there were 275 facilities in the NOx RECLAIM universe.

Under the NOx RECLAIM program, the RECLAIM facilities were first issued annual allocations of NOx emissions (also known as facility caps) in 1993 and the facility cap reflected BARCT in effect at that time. RECLAIM facilities have the flexibility to install air pollution control equipment, change their operations, or purchase RECLAIM Trading Credits (RTCs). The NOx RECLAIM facilities are required to reconcile the actual facility emissions with the annual allocations. The annual allocations were designed to decline annually from 1993 until 2003 and remained constant after 2003, when the SCAQMD conducted a BARCT reassessment for NOx in 2005 and another for SOx in 2010, and subsequently reduced the facility annual allocations further.

To assure a more liquid market, as well as protect RECLAIM participants from price fluctuations that may be caused if all the RTCs expire at the same time, two trading cycles were established. Further, to balance emissions among the participating facilities in the RECLAIM program, the affected facilities were randomly divided into two cycles which vary by compliance year. That is, the Cycle 1 compliance year spans from January 1 to December 31 while the Cycle 2 compliance year spans from July 1 to June 30. A backstop level of $15,000 per ton was established to trigger program reevaluation.

Between compliance year 1994 and compliance year 1999, NOx emissions at RECLAIM facilities, in aggregate, were below the annual allocations, and the price of NOx RTCs remained relatively stable, ranging from $1,500 to $3,000 per ton. However, beginning June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RTC prices for both 1999 and 2000 compliance years. This was mainly due to an increased demand for power generation due to the California energy situation and the delay of installing NOx control equipment by many power plant operators, which resulted in the power-generating industry purchasing a large quantity of RTCs and depleting the supply of available RTCs. The average price of NOx RTCs for compliance year 2000, traded in the year 2000 increased sharply to over $45,000 per ton compared to the average price of $4,284 per ton traded in 1999. Since the RTC price for NOx exceeded the backstop price of $15,000 per ton, an evaluation of the RECLAIM program was triggered.

The Governing Board, at its October 2000 meeting, directed staff to examine the issues affecting the high price of NOx RTCs and recommend actions to stabilize NOx RTC prices. Additionally, the Governing Board directed the Executive Officer to form an Advisory Committee to provide input to staff regarding possible approaches to stabilize NOx RTC prices. Fourteen power producing facilities, each with a generating capacity of 50 megawatts (MW) or greater, purchased 67 percent of the NOx RTCs that were traded during compliance year 2000, suggesting that the increased demand and high prices of NOx RTCs were primarily due to the power producers. However, the annual allocations for all the power producers only accounted for approximately 14 percent of total RECLAIM annual allocations for compliance year 2000. At the same time, the RECLAIM program reached the ‘cross-over point’ where emissions equal allocations because many RECLAIM facilities, relying on previously low RTC prices, did not determine that it was more cost-effective to begin installing controls until after the RTC prices had peaked.

In recognition of the inherent lag time between the ability of facility operators to actually install and operate new control equipment, the Governing Board concluded that immediate changes to the RECLAIM program were necessary and, at the January 19, 2001 Board Meeting, directed staff to form a working group to develop and propose amendments to the RECLAIM program. The goal of the proposed amendments was to implement realistic, effective solutions to reduce and stabilize the prices of NOx RTCs. In May 2001, Regulation XX was amended to place trading restrictions on power producing facilities with the caveat that they could fully rejoin the trading market in the 2004 compliance year, provided that the Governing Board determined prior to July 2003 that their re-entry would not result in any negative effect on the remainder of the RECLAIM facilities or on California’s energy security needs. In addition, the amendments also required the power plants to install BARCT and introduced credit generating rules. Lastly, a Mitigation Fee Program was established for the power plants to make up excess emissions through an option to pay a fee used by the SCAQMD to mitigate emissions through alternative means or programs.

Pursuant to these requirements, SCAQMD staff examined the energy security needs of California and the potential impacts on the RECLAIM market. The Governing Board determined that reentry of the power plants would not be expected to have a negative effect on California’s energy security needs or on other RECLAIM facilities. Overall, power plants equipped with BARCT have reduced their NOx emission rates by approximately 80 percent or more from previously uncontrolled levels.

Based on these emission levels, the 14 power producing facilities are anticipated to emit a total of 1,395 tons per year of NOx and their total annual allocations are 1,705 tons per year for each year from 2003 to 2010. Further, the RTC holdings for the compliance years 2003 through 2010 range from 1,550 to 2,330 tons per year of NOx. This represented a surplus in the NOx RTC holdings at the time ranging from 155 to 935 tons per year. When considering the data relative to the typical annual operational capacity of a power producing unit at below 30 percent, except for 2001 when in-Basin units operated at 35 percent capacity, on average it would take all units operating at a capacity of 55 percent to cause a shortage in NOx RTCs. Therefore, based on the projected excess RTCs and typical operating capacities, power producers were then considered likely to be sellers of NOx RTCs in the RECLAIM program. For these reasons, the Governing Board at the June 6, 2003 public hearing, made the finding that lifting the trading restrictions for power producers in the RECLAIM trading market would not have a negative effect on the remainder of the RECLAIM facilities or on California’s energy security needs. Subsequently, the Governing Board adopted proposed changes to RECLAIM Rules 2007, 2011, and 2012 at the December 5, 2003 public hearing which removed most of the trading restrictions on power producers. As a result, effective September 2004, the power producers were given unrestricted use of RTCs.

On January 7, 2005, amendments were made to the NOx RECLAIM program that resulted in a reduction of RTCs across the board by 7.7 tons per day, based on a BARCT evaluation. The RTCs were reduced from compliance years 2007 to 2011. The total RTCs in the NOx RECLAIM universe allocated in compliance year 2011 amounted to 26.5 tons per day. The audited emissions in compliance year 2011 were 20.01 tons per day, equating to 6.49 tons per day of excess holdings.

In accordance with the Health and Safety Code (HSC) ~~§~~§40440~~ and 39616~~[1], an additional BARCT assessment of the NOx RECLAIM program is once again required to: 1) assess the advancement in control technology; 2) to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach; 3) to ensure that emission reductions from the NOx RECLAIM program contribute towards achieving the federal National Ambient Air Quality Standards (NAAQS); and, 4) to assure that the participating facilities will continue to achieve emission reductions as expeditiously as possible to carry out the commitments in the 2012 AQMP. Except for power producing facilities, the proposed RTC shave reduction will be based on compliance year 2011 activity levels for all other affected facilities. The 2012 activity levels will be used for RTC reductions from power producing facilities because this activity level better represents this sector's energy consumption.

2.2 PROJECT OBJECTIVES

CEQA Guidelines §15124 (b) requires a statement of objectives to describe the underlying purpose of the proposed project. The purpose of the statement of objectives is to aid the lead agency in developing a reasonable range of alternatives to evaluate in the EIR (or equivalent CEQA document) and to aid the decision-makers in preparing a statement of findings and a statement of overriding considerations, if necessary. The objectives of the proposed project are to:

1) Comply with the requirements in Health and Safety Code (HSC) ~~§~~§40440 ~~and 39616~~[1] by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT;
2) Modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment;
3) Ensure that RECLAIM facilities, in aggregate, achieve the same emission reductions that would have occurred under a command-and-control approach;
4) Achieve the proposed NOx emission reduction commitments in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM; and,
5) Achieve NOx emission reductions to assist in attaining the NAAQS.

[1] The reference to Health and Safety Code §39616 has been deleted because it does not require a BARCT analysis. The RECLAIM program proposed here satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so.

2.3 PROJECT DESCRIPTION

To comply with the requirements in HSC §§40440~~ and 39616~~[1], SCAQMD staff conducted a BARCT assessment of the NOx RECLAIM program which resulted in adjusting BARCT levels for both equipment and source categories in the refinery and non-refinery sectors. For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters rated great than 40 mmBTU/hr, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal heat treating furnaces rated great than 150 mmBTU/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for 30 EGFs~~power plants~~. Tables 2-1 and 2-2 summarize the proposed 2015 BARCT levels for the refinery and non-refinery sectors, respectively, along with the associated projected NOx emission reductions.

Table 2-1
Proposed 2015 BARCT Levels and Projected NOx Emission Reductions for Refinery Sector

Refinery Sector Equipment/Source Category	Proposed 2015 BARCT Level	Projected NOx Emission Reductions (tpd)
FCCUs	2 ppmv at 3% O2	0.43
Refinery Boilers and Heaters rated at >40 mmBTU/hr	2 ppmv or 0.002 lb/mmbtu	0.94 ~~0.96~~
Refinery Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
SRU/TGUs	2 ppmv at 3% O2 or 95% reduction	0.32
	TOTAL	**6.00 ~~6.02~~**

Note: tpd = tons per day

Table 2-2
Proposed 2015 BARCT Levels and Projected NOx Emission Reductions for Non-Refinery Sector

Non-Refinery Sector Equipment/Source Category	Proposed 2015 BARCT Level	Projected NOx Emission Reductions (tpd)
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Metal Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
Internal Combustion Engines (non-OCS)	11 ppmv at 15% O2	0.84
Cement Kilns	0.5 lbs/ton	1.29*
	Total	**2.77**

Note: tpd = tons per day

* The 1.29 tpd of projected NOx emission reductions from cement kilns were not included in the total of 2.77 tpd projected NOx emission reductions for the non-refinery sector because the cement kilns that were originally operated at CPCC that would otherwise be subject to a BARCT reassessment were not in operation in 2011. However, because the cement kilns were the top source of NOx emissions in 2008, SCAQMD staff conducted a BARCT analysis for cement kilns and reduced the remaining emissions projected to the 2023 level for the cement facility to the BARCT level.

The total combined BARCT-equivalent emission reductions from the refinery and non-refinery sectors are 8.77 ~~8.79~~ tpd (6.00 ~~6.02~~ tpd for the refinery sector plus 2.77 tpd for the non-refinery sector.) To account for projected growth[2] amongst the sectors, the remaining emissions in 2023 at these proposed 2015 BARCT levels would be 10.23 ~~10.18~~ tpd (2.76 ~~2.71~~ tpd for the refinery sector plus 7.47 tpd for the non-refinery sector). In addition, a 10 percent compliance margin has been added to the remaining emissions to account for uncertainties that arose in the BARCT analysis and to account for facilities that have shut down operations. Finally, ~~an adjustment~~ a Regional NSR Holding A~~a~~ccount to hold RTCs for EGFs ~~power plants~~ to meet their NSR holding obligations is also proposed. Currently, there are 26.5 tpd of NOx RTC holdings. Overall, a total of 14 tpd of NOx RTC reductions from the current RTC holdings of 26.5 tpd is proposed[3]. To help the Basin achieve the PM2.5 standard by 2024 and the ozone standard by 2032, 14 tpd of NOx RTC reductions are proposed to be implemented over a seven-year period from 2016 to 2022.

For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will only affect 56 ~~65~~ facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 219 ~~210~~ facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified for the types of equipment and source categories at these facilities. By following this approach, the shave is distributed as follows:

- 66~~67~~% shave for 9 refineries and investors (treated as one facility)
- 49~~47~~% shave for 21 ~~30 power plants~~ electricity generating facilities
- 49 ~~47~~% shave for 26 non-major facilities
- 0% shave for 219 ~~210~~ remaining facilities

In addition, the overall NOx RTC reductions of 14 tpd is expected to be achieved incrementally from 2016 to 2022, according to the following implementation schedule:

- 2016 – 4 tons per day
- 2018 – 2 tons per day
- 2019 – 2 tons per day
- 2020 – 2 tons per day
- 2021 – 2 tons per day
- 2022 – 2 tons per day

In particular, the proposed project is estimated to reduce four tons per day of NOx emissions starting in 2016 because the amount of unused RTCs in the NOX RECLAIM program over the past five years (e.g., from 2009 to 2013) ranged from five tpd to eight tpd, demonstrating that there is enough cushion to support reduction of four tpd in 2016. However, because it could take from two to four years for the affected facilities to plan, obtain permits, and install air pollution control equipment or modify existing equipment in response to the proposed project, the

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[2] The growth factor assumptions are: 1) 1.0 for the refinery sector; 2) 0.89 for power plants; and 3) 1.1 for the non-refinery sector.

[3] RTC Reductions = RTC Holdings – Remaining Emissions in 2023 - Adjustments = 14 tpd

remaining shave of 10 tpd is scheduled to take place over the five-year period from 2018 to 2022.

To incorporate the proposed NOx RTC shave and implementation schedule, amendments to the NOx RECLAIM regulation are proposed to establish procedures and criteria for reducing NOx RECLAIM RTCs and NOx RTC adjustment factors for year 2016. The proposed amendments contain the following key elements:

- Amend Rule 2001 – Applicability, to allow the owner or operator of an EGF to opt out of the NOx RECLAIM program.
- Amend Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to establish procedures and criteria for reducing NOx RTCs and NOx RTC adjustment factors for year 2016 and later.
- Amend Rule 2002 to add new BARCT emission factors ending in 2021 for an assortment of equipment/process categories.
- Amend Rule 2002 to change the maximum $15,000 per ton price trigger to $22,500 per ton (discrete credits, 12-month rolling average) and add a maximum trigger level of $35,000 per ton (discrete credits, 3-month rolling average).
- Amend Rule 2002 to delete the provisions pertaining to RTC Reductions Exemptions.
- Amend Rule 2002 to add provisions to address the retirement of RTCs from complete facility closure or equipment shutdowns.
- Amend Rule 2002 to allow new EGFs~~power producers~~: 1) the use of the ~~Adjustment~~ Regional NSR Holding Account for their New Source Review holding requirement; and, 2) access to this account during a Governor's declared state of emergency.
- Amend Rule 2005 – New Source Review for RECLAIM, to establish a~~n~~ ~~Adjustment~~ Regional NSR Holding Account for EGF ~~power plant~~ New Source Review holding requirements and set criteria for the use of those RTCs in the event the Governor declares a state of emergency for power generation.
- Amend Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
- Amend Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
- Make administrative and other minor changes such as correcting typographical errors as well as clarifying and updating the rule and rule protocol language for consistency.

Other minor changes are proposed for clarity and consistency throughout the proposed amended regulation. Instructions for obtaining the latest version ~~A copy~~ of PARs 2001, 2002 and 2005 can be found in Appendices A1, A2, and B, respectively of this ~~Draft~~ Final PEA. Instructions for obtaining the latest version ~~A copy~~ of the proposed amended protocols for Rules 2011 and 2012 can be found in Appendices C and D, respectively.

The following is a more detailed summary of the key proposed amendments to the affected rules and protocols that comprise Regulation XX.

PAR 2001

Exit from RECLAIM – subdivision (g)

- Add paragraph (g)(1) to provide an electricity generating facility (EGF) the option of exiting from the NOx RECLAIM program. This opting out of NOx RECLAIM would be contingent upon the submittal of a plan application subject to plan fees specified in Rule 306 and the criteria specified in this paragraph.
- Add subparagraph (g)(2)(A) to specify permit conditions relative to opting out of NOx RECLAIM for new and existing EGFs (see clauses (g)(2)(A)(i) and (g)(2)(A)(ii), respectively).
- Add subparagraph (g)(2)(B) to ensure that an EGF operator will not exceed its respective BACT or BARCT levels of emissions or any existing permit condition limiting NOx emission that is lower than BACT or BARCT as of the date of the opt-out plan submittal.
- Add subparagraph (g)(2)(C) to limit total facility emissions to the amount of RTCs held as of September 22, 2015 in the same proportion as its share of the EGF's emissions during the three completed compliance years prior to the date of opt-out plan submittal.
- Add subparagraph (g)(2)(D) to limit emissions from each NOx source to the amount of RTCs required to be held for that source pursuant to Rule 2005 as of the date of the opt-out plan submittal, applicable to EGFs for which all permits were issued on or after January 1, 1994.
- Add subparagraph (g)(2)(E) to clarify that subdivision (j) – Rule Applicability, would not apply to the EGF for any equipment installed or modified after the date of approval of the opt-out plan, and for existing equipment at the earliest practicable date but no later than three years after the date of the approved opt-out plan.
- Add subparagraph (g)(2)(F) to require an EGF operator to continue to comply with the requirements of Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions and its associated protocols unless the Executive Officer has approved an alternative monitoring and recordkeeping plan which is sufficient to determine compliance with all applicable rules.
- Add subparagraph (g)(2)(G) to clarify for EGFs that are not subject to Regulation XXX – Title V Permits that the EGF's permit must be re-designated as an "opt-out facility permit" and shall remain in effect, subject to annual renewal, unless expired, revoked, or modified pursuant to applicable rules. The EGF operator must continue to pay RECLAIM permit fees pursuant to Rule 301 (l).
- Add paragraph (g)(3) to provide criteria for the Executive Officer to approve or disapprove the opt-out plan.
- Revise paragraph (g)(4) to remove an approved EGF from the list of facilities not allowed to be removed from NOx RECLAIM.

Exemptions – subdivision (i)

- Add subparagraphs (i)(1)(K) and (i)(2)(O) joining approved EGFs to the list facilities exempt from NOx RECLAIM.

PAR 2002

RECLAIM Allocations – subdivision (b)

- Clarify in new paragraph (b)(5) that emission data submitted pursuant to Rule 301 paragraph (l)(10) shall not be considered in determining facility Allocation if new or amended data is submitted more than five years after the original due date.

Annual Allocations for NOx and SOX and Adjustments to RTC Holdings – subdivision (f)

- Delete the Non-tradable/Non-usable NOx RTC Adjustment Factor column ~~Change compliance year "2011 and after" to "2011 to 2015" for the existing NOx RTC adjustment factors~~ in subparagraph (f)(1)(A).
- Add new RTC adjustment factors to subparagraphs (f)(1)(B) and (f)(1)(C) for tradable/usable and non-tradable/non-usable NOx RTCs for facilities listed in Tables 7 and 8, respectively, in order to achieve projected NOx emission reductions from NOx RTC holders beginning in compliance year 2016 and later.
- Clarify in new subparagraph (f)(1)(D) that RTCs which are designated as non-tradeable/non-usable shall be held, but not used or traded.
- Add new subparagraph (f)(1)(E) staff to establish a 3-month averaging period to be used for the price threshold value in subparagraph (f)(1)(I).
- Add new subparagraph (f)(1)(F) to establish procedures for submitting the Non-tradable/Non-usable NOx RTCs as part of the State Implementation Plan commitment.
- Add new subparagraph (f)(1)(G) to establish procedures for transferring the amount of NOx RTCs holdings listed in Table 9 of Rule 2002 to the Regional NSR Holding account.
- Add new subparagraph (f)(1)(H) to allow the EGFs identified in Table 9 to use a combination of their Tradable/Usable and Non-tradable/Non-usable RTCs and the amount for each facility listed in Table 9 (i.e., the RTCs in the Regional NSR Holding account).
- Revise subparagraph (f)(1)(I) to add a RTC price threshold of $35,000 per ton (discrete year credits) based on a 3-month averaging period and to change the price threshold from $15,000 to $22,500 per ton (discrete year credits) for the 12-month averaging period.
- Add new subparagraph (f)(1)(J) to establish a minimum price threshold of $200,000 per ton (infinite year block) based on the 12-month rolling average. For the purpose of Rule 2002, infinite year block refers to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.
- Revise subparagraph (f)(1)(K) to require a report to the Board if the price thresholds are exceeded (subparagraph (f)(1)(I)) or fall below (subparagraph (f)(1)(J)) that includes a commitment and schedule for conducting a more rigorous control technology implementation, emission reduction, cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program. This report to the Board will be made at a public hearing at the earliest possible regularly scheduled Board Meeting, but no more than 90 days from the determination.

- Revise subparagraph (f)(1)(L) to include the NOx RTC adjustment factors for compliance years 2016, and 2018 through 2022 in the State Implementation Plan.
- Revise subparagraph (f)(1)(M) to c~~C~~larify procedures for determining NOx RTC Allocation for facilities entering the RECLAIM program after the date of adoption~~January 7, 2005 in subparagraph (f)(1)(K) to reflect the new RTC adjustment factors added to subparagraphs (f)(1)(B) and (f)(1)(C)~~.
- Revise paragraph (f)(4) to add new procedures for converting Non-tradable/Non-usable RTCs and the Regional NSR Holding Account during a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries.
- Revise paragraph (f)(5) to require the Executive Officer to report to the Governing Board within 60 days of the end of the quarter in which the State of Emergency was declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries.
- ~~Add new allowance in paragraph (f)(4) for all power producing facilities that have received SCAQMD Permits to Construct on or after October 15, 1993 to have access to an Adjustment Account in order to comply with the new source review holding requirements in subdivision (f) of Rule 2005.~~
- ~~Add criteria in paragraph (f)(5) for all power producing facilities to have access to an Adjustment Account RTCs during a State of Emergency as declared by the Governor. The amount and distribution of the RTCs will be determined by the SCAQMD's Executive Officer and will take into account the impact that the State of Emergency has on the RECLAIM program.~~

RTC Reduction Exemption – subdivision (i)

- Staff is proposing to replace this subdivision in its entirety with a new subdivision on Facility and Equipment Shutdowns.
- ~~Clarify paragraph (i)(1) that the RTC reduction exemption does not include RTC holdings for compliance year 2016 and thereafter.~~
- ~~Clarify subparagraph (i)(1)(B) that the application for an RTC reduction exemption needs to demonstrate that the reported emissions for Compliance Year 2013 are not from equipment listed in existing Table 3 or new Table 6 and that the achieved emission rates are less than the emission factors listed in existing Table 3 or new Table 6, whichever is lower.~~
- ~~Clarify subparagraphs (i)(1)(C) and (i)(2)(C) that the application for an RTC reduction exemption needs to demonstrate that the RTCs for Compliance Year 2016 have never been transferred or sold by the facility.~~
- ~~Clarify clause (i)(1)(D)(i) to allow the exclusion of control costs for any equipment listed in existing Table 3 or new Table 6.~~
- ~~Clarify paragraph (i)(3) that an application for an RTC reduction exemption shall be submitted no later than six months after the adoption of the proposed project.~~

- ~~Clarify paragraph (i)(8) to require a facility qualifying for an exemption to include emissions from equipment listed in existing Table 3 or new Table 6 in its Annual Permit Emission Program (APEP) report.~~

Facility and Equipment Shutdowns – subdivision (i)

- Add new paragraph (i)(1) to require the highest ranking official of any facility selling any infinite year block (IYB) RTCs to provide the Executive Officer a written statement that there is no intention to shut down the facility. For the purpose of this rule, IYB refer to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years. This requirement would go into effect on the adoption date of the amendment.
- Add new paragraph (i)(2) to define the criteria for a permanently shut down facility.
- Add new paragraph (i)(3) to specify the amount of NOx RTCs that would be required to be surrendered as part of the facility shutdown.
- Add new paragraph (i)(4) to exempt equipment from being counted against facility shutdowns if the equipment's operational capacity is replaced by new or existing equipment serving the same functional needs at the same facility or another facility under common control.

RECLAIM NOx 2021 Ending Emission Factors – new Table 6

- Add new BARCT emission factors up to the year 2021 for certain boilers and heaters, cement kilns, FCCUs, gas turbines, container glass melting furnaces, permitted ICEs, metal heat treating furnaces, petroleum coke calciners, sodium silicate furnaces, and SRU/TGUs.

List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(B) – new Table 7

- Add new table which identifies the specific facilities (e.g., major refineries and coke calciner) that will be subject to the NOx RTC holdings adjustment factors in subparagraph (f)(1)(B).

List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(C) – new Table 8

- Add new table which identifies the specific facilities that will be subject to the NOx RTC holdings adjustment factors in subparagraph (f)(1)(C).

List of NOx RECLAIM Facilities for the Regional NSR Holding Account with Balances (in lbs) – new Table 9

- Add new table which identifies the specific facilities that will access the Regional NSR Holding Account. This table is referenced in subparagraphs (f)(1)(G) and (f)(1)(H).

PAR 2005

Requirements for New or Relocated RECLAIM Facilities – Subdivision (b)

- Amend subparagraph (b)(2)(A) to clarify the Facility Permit approval criteria in that a facility demonstrating that they hold sufficient RTCs will also need to demonstrate that they hold sufficient RTCs accessed from the Regional NSR Holding ~~Adjustment~~ Account per subparagraphs (f)(1)(G) and (f)(1)(H) ~~(f)(4)~~ of Rule 2002.

Offsets – Subdivision (f)

- Amend paragraphs (f)(2) and (f)(3) by excluding Regional NSR Holding ~~Adjustment~~ Account RTCs from the selling limitations that currently applies to unused RTCs.

Rule 2011 Appendix A (SOx Protocol for Rule 2011)

Attachment C - Quality Assurance and Quality Control Procedures

- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of a major source.
- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of an electricity ~~electrical~~ generating facility (EGF).

Rule 2012 Appendix A (NOx Protocol for Rule 2012)

Attachment C - Quality Assurance and Quality Control Procedures

- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of a major source.
- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of an electricity ~~electrical~~ generating facility (EGF).

2.4 TECHNOLOGY OVERVIEW

NOx Emission Sources

The NOx RECLAIM program currently consists of 275 facilities as of the 2013 compliance year. SCAQMD staff conducted a BARCT analysis for these 275 facilities. Of these, 21 EGFs ~~30 power producing facilities~~ where shown to operate at current BARCT or BACT levels. For 219 ~~224~~ facilities, either no new BARCT was identified or the installation of control equipment was determined to not be cost-effective and/or infeasible. Further, only 35 ~~44~~ facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact. In addition, the sale and/or purchase of RTCs by investors (treated as one facility) will also have no environmental impact.

SCAQMD staff conducted an analysis of the potential feasibility and cost-effectiveness of adding controls to reduce NOx from the remaining 21 facilities (e.g., 275 - 21 EGFs (with shave) ~~30 power producers~~ - 224 non-power plant facilities – 9 EGFs (without shave) = 21) which are either major or large sources of NOx for which new BARCT has been identified. Further, 19 of the 21 facilities are also among the top NOx RTC holders.

The BARCT analysis further found that it would be both feasible and cost-effective for facility operators to install new control equipment or modify existing control equipment in response to the proposed NOx RTC shave for facilities which operate with current SCAQMD permits. Of the 21 facilities, 12 facilities belong to the non-refinery sector and 9 facilities belong to the refinery sector. These facilities are identified as follows:

<u>Nine Facilities in the Refinery Sector:</u>

- Six refineries owned by five companies operate FCCUs, refinery boilers and heaters, refinery gas turbines, and SRU/TGUs: Tesoro (two locations: Wilmington and Carson); Phillips 66 (two locations: Wilmington and Carson); Chevron; ExxonMobil; and, Ultramar (also referred to as Valero)
- One sulfur plant: Tesoro (Wilmington location)
- One coke calciner plant: Tesoro (Wilmington location)

Of the above-listed facilities, six refineries operate one FCCU each, one SRU/TGU each, and a multitude of refinery process heaters and boilers and refinery gas turbines. The quantity of major and large source NOx emissions from the refineries comprises approximately 54 percent of the total NOx emitted from the universe of RECLAIM facilities in compliance year 2011.

<u>12 Facilities in the Non-Refinery Sector:</u>

- One container glass manufacturing plant: Owens-Brockway Glass Container Inc.
- One sodium silicate manufacturing plant: PQ Corporation
- One steel plant operating two metal heat treating furnaces rated greater than > 150 million British Thermal Units per hr (mmBTU/hr): California Steel
- Seven facilities operating gas turbines: Southern California Gas Company, SDGE, THUMS Long Beach, Wheelabrator Norwalk Energy, LA City Department of Airports, Tin Inc., and Berry Petroleum
- Three facilities operating IC Engines: SDGE and Southern California Gas Company (two facilities)
- One facility operating Portland cement kilns: CPCC

The major and large sources belonging to non-refineries among the top NOx emitting facilities that were analyzed for BARCT emitted 18 percent of the RECLAIM universe's total emissions inventory in compliance year 2011.

It is important to note that CPCC is no longer operating their Portland cement kilns with current SCAQMD permits. Because CPCC's operators hold NOx RTCs, the BARCT analysis can be applied to this facility by shaving their NOx RTCs holdings. However, because the affected equipment is not operational, the installation of BARCT control equipment would not be expected.

In conclusion, the proposed project may result in the installation of new or the modification of existing NOx emission control equipment for 20 of these industrial equipment and processes (e.g., 9 facilities from the refinery sector and 11 facilities from the non-refinery sector) and Portland cement kilns are excluded from this assumption for reasons that are further explained in the Portland Cement Kiln discussion under the Non-Refinery / Non-Power Plant Category section later in this chapter.

<u>Combustion Equipment</u>

Combustion is a high temperature chemical reaction resulting from burning a gas, liquid, or solid fuel (e.g., natural gas, diesel, fuel oil, gasoline, propane, and coal) in the presence of air (oxygen and nitrogen) to produce: 1) heat energy; and, 2) water vapor or steam. An ideal combustion reaction is when the entire amount of fuel needed is completely combusted in the presence of air so that only carbon dioxide (CO2) and water are produced as by-products. However, since fuel contains other components such as nitrogen and sulfur plus the amount of air mixed with the fuel can vary, in practice, the combustion of fuel is not a "perfect" reaction. As such, uncombusted fuel plus smog-forming by-products such as NOx, SOx, carbon monoxide (CO), and soot (solid carbon) can be discharged into the atmosphere.

Of the total NOx emissions that can be generated, there are two types of NOx formed during combustion: 1) thermal NOx; and, 2) fuel NOx. Thermal NOx is produced from the reaction between the nitrogen and oxygen in the combustion air at high temperatures while fuel NOx is formed from a reaction between the nitrogen already present in the fuel and the available oxygen in the combustion air. As the source of nitrogen in fuel is more prevalent in oil and coal, and is negligible in natural gas, the amount of fuel NOx generated is dependent on fuel type. For example, with oil that contains significant amounts of fuel-bound nitrogen, fuel NOx can account for up to 50 percent of the total NOx emissions generated. In another example, only 10 percent of NOx emissions from FCCUs are thermal NOx while the remaining 90 percent of NOx is generated from fuel by combusting petroleum coke. Though boilers, process heaters, petroleum coke calciners, FCCUs, gas turbines, and other miscellaneous equipment have varying purposes in commercial, industrial, and utility applications, at a minimum, they all generate thermal NOx as a combustion by-product. The following provides a brief description of the various types of existing combustion equipment that may be affected by the proposed amendments to Regulation XX and subsequently retrofitted with NOx control equipment.

REFINERY CATEGORY

<u>Refinery Process Heaters and Boilers</u>

Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking.

A process heater is a type of combustion equipment that burns liquid, gaseous, or solid fossil fuel for the purpose of transferring heat from combustion gases to heat water or process streams. Process heaters are not kilns or ovens used for drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

A typical boiler, also referred to as a steam generator, is a steel or cast-iron pressure vessel equipped with burners that combust liquid, gas, or solid fossil fuel to produce steam or hot water. Boilers are classified according to the amount of energy output in millions of British Thermal Units per hour (mmBTU/hr), the type of fuel burned (natural gas, diesel, fuel oil, etc.), operating steam pressure in pounds per square inch (psi), and heat transfer media. In addition, boilers are further defined by the type of burners used and air pollution control techniques. The burner is where the fuel and combustion air are introduced, mixed, and then combusted.

There are a total of 212 boilers and heaters classified as major and large NOx sources at the refineries (23 boilers and 189 heaters). Collectively, the 212 boilers and heaters emitted approximately 7.39 tons per day in 2011.

Refinery process heaters and boilers are primarily fueled by refinery gas, one of several products generated at the refinery. In addition, most of the refinery process heaters and boilers are designed to also operate on natural gas, but liquid or solid fuels are rarely used. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

For the purpose of the analysis in this PEA, controlling NOx emissions from refinery boilers and process heaters is assumed to be accomplished with selective catalytic reduction (SCR) technology. While low NOx burners may be effective at reducing NOx emissions, SCRs were analyzed because SCR technology has been demonstrated to have more adverse construction and operational impacts than low NOx burners. Thus, by analyzing SCRs in lieu of low NOx burners, the analysis in this PEA applies the most conservative assumptions to represent a "worst-case" scenario. For a full description of this control technology, see the NOx Control Technologies section.

<u>Refinery Gas Turbines</u>

Gas turbines are used in refineries to produce both electricity and steam. Refinery gas turbines are typically combined cycle units that use two work cycles from the same shaft operation. Refinery gas turbines also have an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are cogenerating units that recover the useful energy from heat recovery for producing process steam. There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tons per day of NOx in 2011.

Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40 percent and combined-cycle efficiencies of 60 percent. The existing gas turbines operating at the refineries are rated from seven MW to 83 MW. Most of the refinery gas turbines are operated with duct burners, heat recovery steam generator (HRSG), SCR, and CO catalysts. Figure 2-2 shows a typical layout of a combined cycle utility gas turbine with a duct burner, HRSG, and control system.

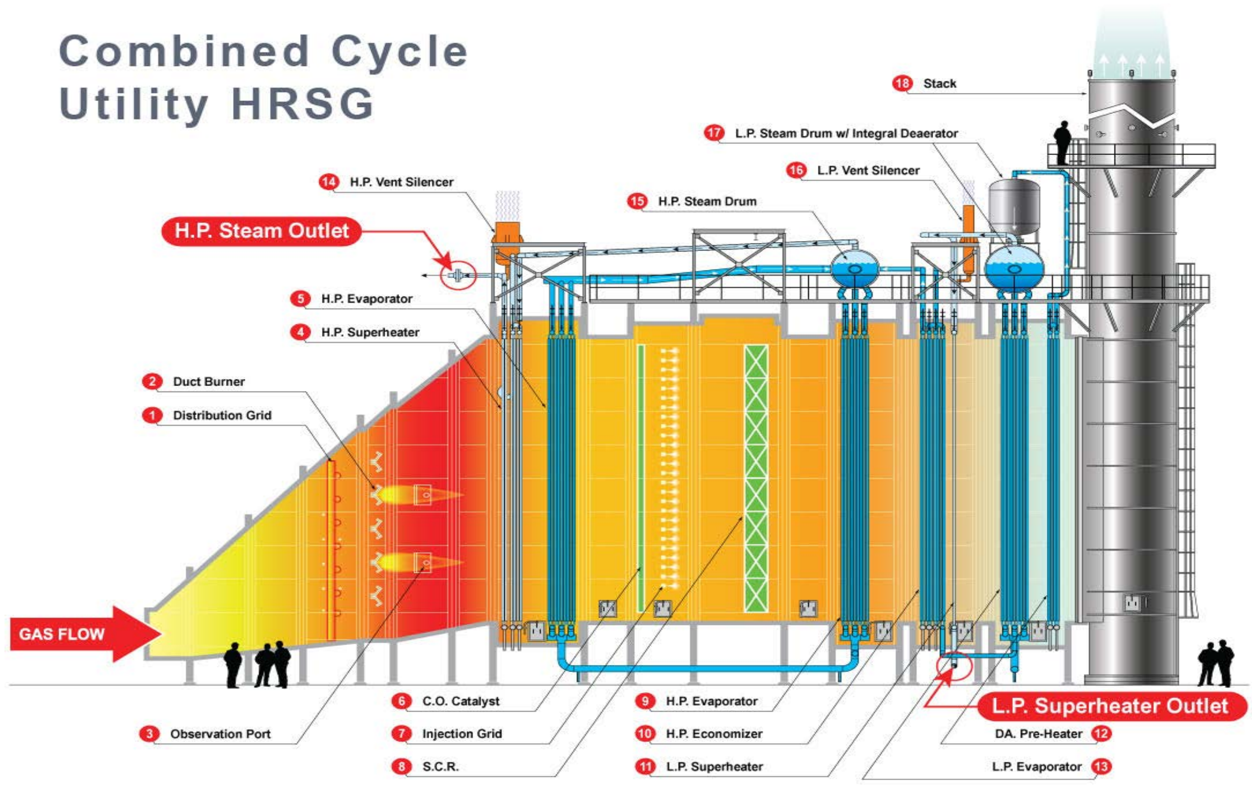

Figure 2-2: Gas Turbine with Duct Burner

For the purpose of the analysis in this PEA, controlling NOx emissions from refinery gas turbines is assumed to be accomplished with SCR technology. For a full description of this control technology, see the NOx Control Technologies section.

Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGTUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal. A typical sulfur removal or recovery system will include a sulfur recovery unit (e.g., Claus unit) followed by a tail gas treatment unit (e.g., amine treating) for maximum removal of hydrogen sulfide (H_2S). A Claus unit consists of a reactor, catalytic converters and condensers. Two chemical reactions occur in a Claus unit. The first reaction occurs in the reactor, where a portion of H_2S reacts with air to form sulfur dioxide (SO_2) followed by a second reaction in the catalytic converters where SO_2 reacts with H_2S to form liquid elemental sulfur. Side reactions producing carbonyl sulfide (COS) and carbon disulfide (CS_2) can also occur. These side reactions are problematic for Claus plant operators because COS and CS_2 cannot be easily converted to elemental sulfur and carbon dioxide. Liquid sulfur is recovered after the final condenser. The combination of two converters with two condensers in series will generally remove as much as 95 percent of the sulfur from the incoming acid gas. To increase removal efficiency, some newer sulfur recovery units may be designed with three to four sets of converters and condensers.

To recover the remaining sulfur compounds after the final pass through the last condenser, the gas is sent to a tail gas treatment process such as a SCOT or Wellman-Lord treatment process. For example, the SCOT tail gas treatment is a process where the tail gas is sent to a catalytic reactor and the sulfur compounds in the tail gas are converted to H_2S. The H_2S is absorbed by a solution of amine or diethanol amine (DEA) in the H_2S absorber, steam-stripped from the absorbent solution in the H_2S stripper, concentrated, and recycled to the front end of the sulfur recovery unit. This approach typically increases the overall sulfur recovery efficiency of the Claus unit to 99.8 percent or higher. However, the fresh acid gas feed rate to the sulfur recovery unit is reduced by the amount of recycled stream, which reduces the capacity of the sulfur recovery unit. The residual H_2S in the treated gas from the absorber is typically vented to a thermal oxidizer where it is oxidized to sulfur dioxide (SO_2) before venting to the atmosphere.

The Wellman-Lord tail gas treatment process is when the sulfur compounds in the tail gas are first incinerated to oxidize to SO_2. After the incinerator, the tail gas enters a SO_2 absorber, where the SO_2 is absorbed in a sodium sulfite (Na_2SO_3) solution to form sodium bisulfite ($NaHSO_3$) and sodium pyrosulfate ($Na_2S_2O_5$). The absorbent rich in SO_2 is then stripped, and the SO_2 is recycled back to the beginning of the Claus unit. The residual sulfur compounds in the treated tail gas from the SO_2 absorber is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before venting to the atmosphere. NOx is a by-product of operating the incinerator.

The type of NOx control option to be utilized in response to this portion of the proposed project is assumed to be LoTOx™ technology with a WGS. For a full description of this control technology, see the NOx Control Technologies section.

Petroleum Coke Calciner

Petroleum coke, the heaviest portion of crude oil, cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as “green coke,” a commodity. To improve the quality of the product, if the green coke has a low metals content, it will be sent to a calciner to make calcined petroleum coke. Calcined petroleum coke can be used to make anodes for the aluminum, steel, and titanium smelting industry. If the green coke has a high metals content, it is used as fuel grade coke by the fuel, cement, steel, calciner and specialty chemicals industries.

As shown in Figure 2-3, the process of making calcined petroleum coke begins when the green coke feed produced by the delayed coker unit is screened and transported to the calciner unit where it is stored in a covered coke storage barn. The screened and dried green coke is introduced into the top end of a rotary kiln and is tumbled by rotation under high temperatures that range between 2000 and 2500 degrees Fahrenheit (^{o}F). The rotary kiln relies on gravity to move coke through the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or fuel oil. As the green coke flows to the bottom of the kiln, it rests in the kiln for approximately one additional hour to eliminate any remaining moisture, impurities, and hydrocarbons. Once discharged from the kiln, the calcined coke is dropped into a cooling chamber, where it is quenched with water, treated with de-dusting agents to minimize dust, carried by conveyors to storage tanks. Eventually, the calcined coke is transported by truck to the Port of Long Beach for export, or is loaded onto railcars for shipping to domestic customers. As the green coke is processed under high heat conditions in the rotary kiln, NOx emissions are generated. NOx is also generated from combusting fuel oil to generate high heating values in the rotary kiln.

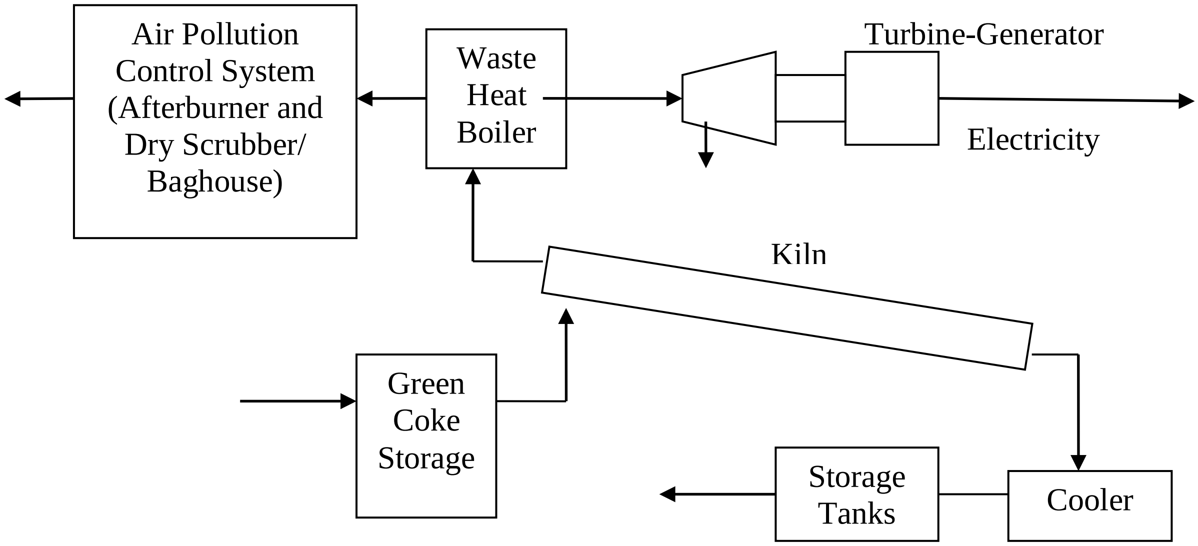

Figure 2-3: Coke Calciner Process

The Tesoro Wilmington coke calciner is the only petroleum coke calciner in the Basin and produces approximately 400,000 short tons per year of calcined products. This petroleum coke calciner is a global supplier of calcined coke to the aluminum industry, and fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses. The existing control system also includes a spray dryer, a reverse-air baghouse, a slurry storage system, a slurry circulating system, and a pneumatic conveying system. Calcium hydroxide (CaOH) slurry is the absorbing medium for SO_2 control.

There are two commercially available multi-pollutant control technologies for the low temperature removal of NOx emissions from the coke calciner: 1) LoTOx^{TM} with scrubber; and, 2) UltraCat. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for the coke calciner in response to the proposed project will depend on this facility's individual operations and the current control technologies and techniques in place. Thus, the ~~Draft~~ Final PEA will evaluate the possibility that operators of the petroleum coke calcining facility may rely on either of the above-mentioned control technologies to further control NOx emissions in order to comply with the BARCT requirements for the petroleum coke calcining portion of the proposed project. For a full description of these control technologies, see the NOx Control Technologies section.

FCCUs

The purpose of an FCCU at a refinery is to convert or "crack" heavy oils (hydrocarbons), with the assistance of a catalyst, into gasoline and lighter petroleum products. Each FCCU consists of three main components: a reaction chamber, a catalyst regenerator and a fractionator. All six refineries each operate one FCCU.

As shown in Figure 2-4, the cracking process begins in the reaction chamber where fresh catalyst is mixed with pre-heated heavy oils (crude) known as the fresh feed. The catalyst typically used for cracking is a fine powder made up of tiny particles with surfaces covered by several microscopic pores. A high heat-generating chemical reaction occurs that converts the heavy oil liquid into a cracked hydrocarbon vapor mixed with catalyst. As the cracking reaction progresses, the cracked hydrocarbon vapor is routed to a distillation column or fractionator for further separation into lighter hydrocarbon components than crude such as light gases, gasoline, light gas oil, and cycle oil.

Towards the end of the reaction, the catalyst surface becomes inactive or spent because the pores are gradually coated with a combination of heavy oil liquid residue and solid carbon (coke), thereby reducing its efficiency or ability to react with fresh heavy liquid oil in the feed. To prepare the spent catalyst for re-use, the remaining oil residue is removed by steam stripping. The spent catalyst is later cycled to the second component of the FCCU, the regenerator, where hot air burns the coke layer off of the surface of each catalyst particle to produce reactivated or regenerated catalyst. Subsequently, the regenerated catalyst is cycled back to the reaction chamber and mixed with more fresh heavy liquid oil feed. Thus, as the heavy oils enter the cracking process through the reaction chamber and exit the fractionator as lighter components, the catalyst continuously circulates between the reaction chamber and the regenerator.

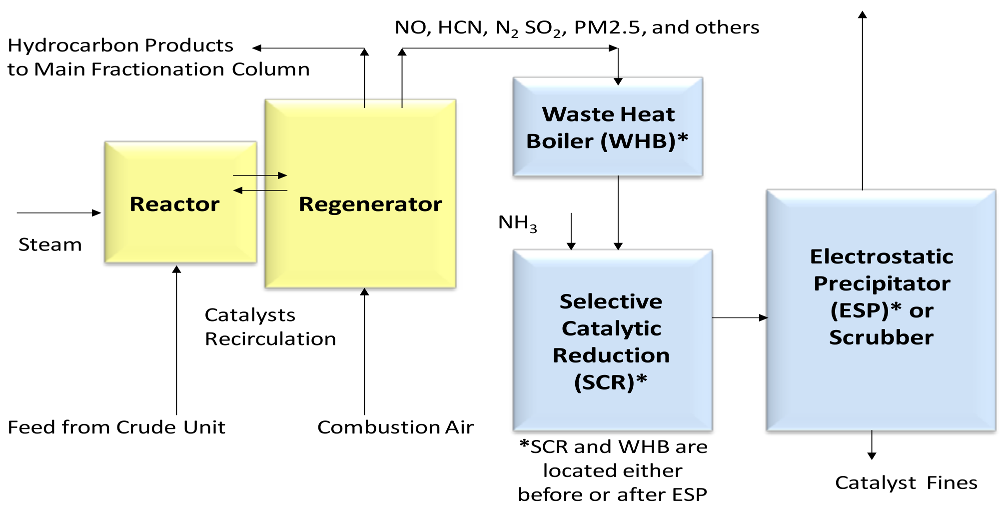

Figure 2-4: Simplified Schematic of FCCU Process

During the regeneration cycle, large quantities of catalyst are lost in the form of catalyst fines or particulates thus making FCCUs a major source of primary particulate emissions (PM10 and PM2.5) at refineries. In addition, particulate (PM) precursor emissions such as SOx (because crude oil naturally contains sulfur) and NOx, additional secondary particulates (i.e., formed as a result of various chemical reactions), plus carbon monoxide (CO) and carbon dioxide (CO_2) are produced due to coke burn-off during the regenerator process.

Approximately 90 percent of the NOx generated from the FCCUs is from the nitrogen in the feed that is accumulated in the coke which is then burned-off in the regenerator. This portion of the NOx is called “fuel” NOx. “Fuel” NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10 percent of the NOx generated from the FCCUs are “thermal” NOx which is generated in the high temperature zones in the regenerator, and “prompt” NOx generated from the reaction between nitrogen and oxygen in the combustion air.

Combustion in a FCCU regenerator generates various pollutants (e.g., NO, N_2O, NO_2, HCN, NH_3, SO_2, etc.) and their dynamic interaction with each other is complex. "Fuel" nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, and NO_2. The rates of these reactions depend heavily on the FCCU regenerator temperatures and configuration.

Currently, refineries may operate FCCUs by utilizing NOx reducing additives to promote the conversion of NOx, HCN, and NH_3 to elemental nitrogen (N_2) and reduce NOx emissions. The removal efficiency for NOx reducing additives can range between 50 percent and 80 percent. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure 2-5.

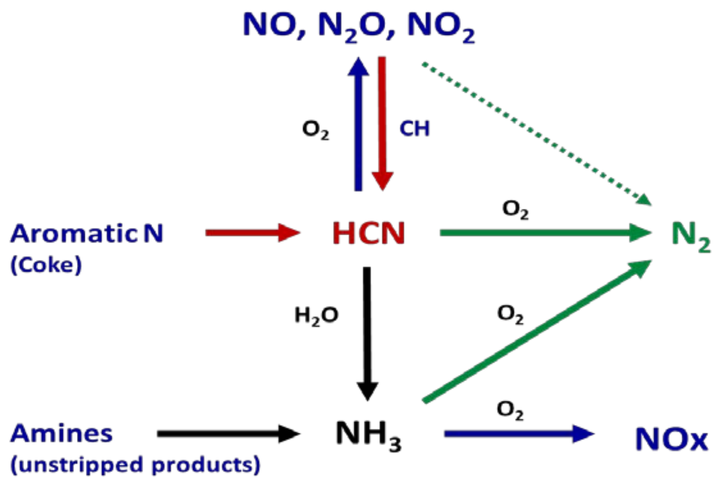

Figure 2-5: Nitrogen Chemistry in the FCCU Regenerator

When using NOx reducing additives, manufacturers recommend the following best practices to minimize the formation of NOx and simultaneously promote the conversion of CO to CO_2: 1) minimize excess oxygen since higher amounts of excess oxygen favors the undesirable formation of NOx rather than N_2; 2) reduce nitrogen in the feed stream; and, 3) utilize non-platinum CO promoters.

To further reduce NOx emissions from a FCCU (beyond what is currently being achieved through the use of NOx reducing additives, the potential available control technologies are either: 1) SCR; or, 2) LoTOx^{TM} with WGS. For a full description of these control technologies, see the NOx Control Technologies section.

NON-REFINERY / NON-POWER PLANT CATEGORY

Portland Cement Kilns

In the NOx RECLAIM program, there is one facility (CPCC) with two cement kilns capable of producing gray cement from limestone, sand, shale, and clay raw materials. The CPCC facility, under normal operation, has typically been among the highest NOx emitters in the RECLAIM program. The manufacturing of gray Portland cement follows a four-step process of: 1) acquiring raw materials; 2) preparing the raw materials to be blended into a raw mix; 3) pyroprocessing of the raw mix to make clinker; and, 4) grinding and milling clinker into cement. The raw materials used for manufacturing cement include calcium, silica, alumina and iron, with calcium having the highest concentration. These raw materials are obtained from a limestone quarry for calcium, sand for silica; and shale and clay for alumina and silica.

The raw materials are crushed, milled, blended into a raw mix and stored. Primary, secondary and tertiary crushers are used to crush the raw materials until they are about ¾-inch or smaller in size. Raw materials are then conveyed to rock storage silos. Belt conveyors are typically used for this transport. Roller mills or ball mills are used to blend and pulverize raw materials into fine powder. Pneumatic conveyors are typically used to transport the fine raw mix to be stored in silos until it is ready to be pyroprocessed.

The pyroprocess in a kiln consists of three phases during which clinker is produced from raw materials undergoing physical changes and chemical reactions. The first phase in a kiln, the drying and pre-heating zone, operates at a temperature between 70 ^{o}F and 1650 ^{o}F and evaporates any remaining water in the raw mix of materials entering the kiln. Essentially this is the warm-up phase which stabilizes the temperature of the refractory fire brick inside the mouth opening of the kiln. The second phase, the calcining zone, operates at a temperature between 1100 ^{o}F and 1650 ^{o}F and converts the calcium carbonate from the limestone in the kiln feed into calcium oxide and releases carbon dioxide. During the third phase, the burning zone operates on average at 2200 ^{o}F to 2700 ^{o}F (though the flame temperature can exceed 3400 ^{o}F) during which several reactions and side reactions occur. The first reaction is calcium oxide (produced during the calcining zone) with silicate to form dicalcium silicate and the second reaction is the melting of calcium oxide with alumina and iron oxide to form the liquid phase of the materials. Despite the high temperatures, the constituents of the kiln feed do not combust during pyroprocessing. As the materials move towards the discharge end of the kiln, the temperature drops and eventually clinker nodules form and volatile constituents, such as sodium, potassium, chlorides, and sulfates, evaporate. Any excess calcium oxide reacts with dicalcium silicate to form tricalcium silicate. The red hot clinker exits the kiln, is cooled in the clinker cooler, passes through a crusher and is conveyed to storage for protection from moisture. Since clinker is water reactive, if it gets wet, it will set into concrete.

Heat needed to operate CPCC's kilns is supplied through the combustion of different fuels such as coal, coke, oil, natural gas, and discarded automobile tires. The combustion gases are vented to a baghouse for dust control, and the collected dust is returned to the process or recycled if they meet certain criteria, or is discarded to landfills. CPCC does not currently have any post-combustion control for NOx emissions.

NOx emissions from the cement kilns are generated from the following: 1) combusting fuel to generate high heating values in the kilns; and, 2) oxidation of raw materials entering the cement kiln. As is the case with CPCC, long, dry cement kilns have achieved NOx reductions to the 2000 (Tier 1) level by utilizing low NOx burners and mid-kiln firing with tire-derived fuel (TDF). With TDF, whole tires are introduced at an inlet location about midway along the kiln's calcining zone. TDF lowers NOx emissions by lowering the flame temperatures and reducing thermal NOx with the introduction of a slower burning fuel.

On November 20, 2009, CPCC operators announced the shutdown of both cement kilns indicating at that time that the shutdown would not be permanent to the extent that when the economy improves, they plan to bring the cement kilns back on-line. At the time the NOP/IS was released for public review and comment, the NOP/IS acknowledged that in the event that CPCC operators decide to fire up its kilns, the type of NOx control technology to be utilized to comply with the proposed project will depend on CPCC's individual operations and how the kilns will function with the current control technologies and techniques in place at CPCC (e.g., the baghouse). The potential available control technologies to reduce NOx emissions from cement kilns were described in the NOP/IS as the following: 1) SCR with or without a WGS; 2) UltraCat; or, 3) SNCR. The NOP/IS committed that the ~~Draft~~ PEA would evaluate the possibility that CPCC operators may rely on the above-mentioned control technologies to further control NOx emissions from cement kilns to comply with the proposed project.

However, on April 9, 2015, after the release of the NOP/IS for public review and comment, CPCC operators have surrendered their operating permits for the cement kilns and have applied for Emission Reduction Credits (ERCs). Thus, because CPCC operators are no longer operating the cement kilns and they no longer hold current SCAQMD operating permits for these units, the existing setting or NOx emissions baseline for the cement kilns at CPCC is zero. Further, if CPCC operators decide to restart the cement kilns in the future, applications for new SCAQMD permits to operate would be required. Further, these permit applications would be subject to an extensive permit review process such that that the cement kilns would be treated as a new installation that would be subject to a new CEQA review and BACT requirements, instead of BARCT. Because of CPCC's current permitting status for these cement kilns, CPCC operators will not be able to retrofit the cement kilns with air pollution control equipment in response to the proposed project without first dealing with the permitting issues for the cement kilns. Thus, the installation of control technology and the secondary adverse environmental impacts that may be associated with such control technology is not a reasonably foreseeable consequence for CPCC under the present circumstances.

When evaluating the significance of the environmental effects of a project, the Lead Agency is required to consider direct physical changes in the environment which may be caused by the project and reasonably foreseeable indirect physical changes in the environment which may be caused by the project [CEQA Guidelines §15064 (d)]. Because the installation of control technology and the adverse environmental impacts that may be associated with such control technology for the CPCC facility are not reasonably foreseeable and because there are no other Portland cement kilns operating within the SCAQMD's jurisdiction, the SCAQMD, as Lead Agency for the proposed project, is not required to consider or analyze the effects of control technology for this facility. Thus, this PEA does not contain an environmental analysis of the control technologies that were originally contemplated in the NOP/IS for the CPCC facility.

<u>Container Glass Melting Furnaces</u>

In the NOx RECLAIM program there is one facility among the top NOx emitting facilities that operates glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

A container glass melting furnace is the main equipment used for manufacturing glass products, such as bottles, glass wares, pressed and blown glass, tempered glass, and safety glass. The manufacturing process consists of four phases: 1) preparing the raw materials; 2) melting the mixture of raw materials in the furnace; 3) forming the desired shape; and, 4) finishing the final product. Raw materials, such as sand, limestone, and soda ash, are crushed and mixed with cullets (recycled glass pieces) to ensure homogeneous melting. The raw materials mixture is then conveyed to a continuous regenerative side-port melting furnace. As the mixture enters the furnace through a feeder, it melts and blends with the molten glass already in the furnace, and eventually flows to a refiner section, to a forming machine, and then, to annealing ovens. The final products undergo inspection, testing, packaging and storage. Any damaged or undesirable glass is transferred back to be recycled as cullet suitable for remelting.

NOx is generated from a container glass melting furnace in two ways: 1) during the decomposition of the silica in the raw materials; and, 2) from combusting fuel to generate high heating values in the furnace. The container glass melting furnace contributes over 99 percent of the total NOx emissions from a glass manufacturing plant. To effectively achieve the largest reduction of NOx emissions, SCR and UltraCat technologies are commercially available options for treating the flue gas of glass melting furnaces. For a full description of these control technologies, see the NOx Control Technologies section.

Sodium Silicate Furnace

In the NOx RECLAIM program, there is only one facility that produces sodium silicate in a melting furnace. Sodium silicate, a type of glass with a wide variety of industrial uses, should not to be confused with container or flat glass. Sodium silicate exists in a solid or liquid form, depending on the temperature. The combination of heating a batch-fed mixture of soda ash and sand causes the materials to produce sodium silicate and CO_2. NOx emissions are also created from combusting fuel needed to heat the furnace. In order to generate high heating values, the furnace is fired by several natural gas-fired burners. The flue gas then exits the furnace via a stack into the atmosphere.

Approximately 15 to 20 percent of NOx emission reductions can be achieved by utilizing blower air staging to lower the flue gas temperature in the furnace. To effectively achieve the largest reduction of NOx emissions, however, SCR technology is best suited for treating the flue gas of sodium silicate furnaces.

In addition, UltraCat, an alternate to SCR technology, is also available for multi-pollutant control. For a full description of these control technologies, see the NOx Control Technologies section.

Metal Heat Treating Furnaces

A metal heat treating furnace burns liquid or gaseous fuel to generate enough pre-heated air at a temperature high enough to melt solid metal and into a liquid molten consistency and to maintain the metal in a liquid state until it is ready for later use. The types of furnaces that are used for metal heat treating are reverberatory, cupola, induction, direct arc furnaces, sweat furnaces, and refining kettles. The burner flame and combustion products come in direct contact with the metal.

Heat treating operations are directly related to the metal producing and secondary metal processing industries. Materials handled by the heat treating industry are a variety of products provided by manufacturers that are used by other manufacturers, to make consumable or usable products. Typical materials used for heat treating are iron, steel, ferro-alloys, glass, and other nonferrous metals. Heat treatment furnaces are used for activities that include forging, hardening, tempering, annealing, normalizing, sintering, and case hardening of steels and solution and heat treatment of corrosion resistant and aluminum metals. Kilns are not considered heat treating furnaces. Among the top NOx emitting facilities in the NOx RECLAIM program, there is only one facility that processes steel in two metal heat treating furnaces with individual heat ratings above 150 mm BTU/hr.

As with all combustion sources, the type of burner used can affect the emissions. Some burners are lower NOx emitting than others. But for these types of furnaces, there are often dozens of burners that cumulatively require a high heat input. To achieve higher efficiency and to consume less fuel, recuperative and regenerative burners are used. These burners employ the principle of using preheated inlet air which is heated by the exhaust gases for more efficient combustion. However, to effectively achieve a substantial NOx reduction from these metal heat treating furnaces, SCR is the technology that is best suited for the flue gas treatment of NOx. For a full description of these control technologies, see the NOx Control Technologies section.

The ~~Draft~~ Final PEA will evaluate the possibility that the operator of the metal heat treating furnaces may rely on SCR technology to further control NOx emissions in order to comply with the BARCT requirements for the metal heat treating furnace portion of the proposed project. For a full description of this control technology, see the NOx Control Technologies section.

Gas Turbines (Non-Refinery/Non-Power Plant)

Stationary gas turbines are used primarily to drive compressors or to generate power. Gas turbines operate either in simple cycle or combined cycle. Simple cycle units use the mechanical energy of shaft work that is transferred to and used by a gas compressor, for example, or to run an electrical generator to produce electricity. A combined cycle unit adds an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Combined cycle units are more efficient due to their use of two work cycles from the same shaft operation. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are not power plant turbines (turbines that produce solely electric utility power). Some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam.

Among the top non-power plant NOx emitting facilities in the RECLAIM universe, there are twenty gas turbines that are either major or large source units. Four of these units are currently utilizing some level of NOx control along with SCR. Six of these units are operated on an offshore oil drilling platform (outer continental shelf, or OCS). The OCS turbines, which are fired on diesel or process gas, have the highest NOx emission concentrations in this source category. Four of the OCS units with lower NOx parts per million (ppm) concentrations currently are equipped with SCR systems.

For the purpose of the analysis in this PEA, controlling NOx emissions from non-refinery/non power plant gas turbines is assumed to be accomplished with SCR technology. For a full description of this control technology, see the NOx Control Technologies section.

Internal Combustion Engines (Non-Refinery/Non-Power Plant)

Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate power. There are generally two types of engines, spark-ignited (SI) or compression ignited (CI) engines. SI engines ignite the air/fuel mixture with a spark while CI engines use the heat of compression to ignite the fuel that is injected into the combustion chamber. Engines can run at either stoichiometrically rich burn or lean burn conditions, depending on the air to fuel ratio. Rich burn combustion corresponds to an air-to-fuel ratio that is fuel-rich while lean burn combustion corresponds to a fuel-lean air-to-fuel ratio. Small SI engines typically run as rich burn, but many larger units as well as CI engines operate under lean burn conditions. For lean burn engines, more air is inducted than is required for complete combustion and the resultant exhaust oxygen level is high (over five percent). Rich burn engines typically operate very close to stoichiometric conditions by drawing only the necessary air to combust the fuel. SI engines are typically fired on gaseous fuels such as natural gas, while CI engines are fired on liquid fuels such as diesel.

Among the top NOx emitting facilities in the RECLAIM universe, there are 31 engines that are either major or large source units. Currently, there are nine rich burn engines equipped non-selective catalytic reduction (NSCR). Of the remaining 22 engines, there are 16 SI lean burn engines units and six CI lean burn units. The CI lean burn units are all operated on an offshore oil drilling platform (outer continental shelf, or OCS). The engine sizes range from a little over 700 brake horsepower (bhp) to 5,500 bhp. Diesel-fueled CI engines have the highest NOx emission concentrations in this source category while two-stroke SI engines have higher NOx emissions than four-stroke SI engines since the higher efficiencies in two-stroke engines translate to a hotter combustion temperature that can create more NOx.

For the ICEs operating at the 238 remaining NOx RECLAIM faculties, the ICEs would also need to meet the BARCT levels on a programmatic basis. The ~~Draft~~ Final PEA will evaluate the possibility that the SCR technology may be relied up in order to comply with the stationary ICEs portion of the proposed project. For a full description of this control technology, see the NOx Control Technologies section.

NOx Control Technologies

As reducing NOx emissions is the main objective of the currently proposed amendments to the RECLAIM program, there are two primary approaches for reducing NOx emissions: 1) by combustion control techniques that minimize the amount of NOx formed by the combustion equipment; or, 2) by installing a device that controls the NOx after it has been generated or post-combustion. At the time the NOP/IS was released, the consultants hired to assess the BARCT control technology options had not yet provided their recommendations or finalized their reports. As such, the NOP/IS contained a comprehensive list of multiple types of potential BARCT control technology options. Subsequently, however, the consultants presented their findings and some of the BARCT control technology options presented in the NOP/IS are now no longer considered to be viable or cost-effective options for the proposed project. For the reader to see how the list of BARCT control technology options changed since the release of the NOP/IS, Table 2-3 summarizes the potential control technologies that were initially considered in the NOP/IS as potential candidates for the BARCT analysis and shows the actual control technologies that are being considered for the BARCT analysis in this PEA. The following discussions will elaborate on the various technologies listed in Table 2-3 for consideration in this PEA.

Table 2-3

BARCT Control Technology Options for Top NOx Emitting Equipment/Processes

Equipment/Process	BARCT Control Technology Options Identified in NOP/IS	BARCT Control Technology To Be Analyzed in PEA
FCCUs	1. SCR 2. LoTOx™ with scrubber 3. NOx reducing additives	1. SCR 2. LoTOx™ with WGS
Refinery Process Heaters and Boilers	1. SCR 2. LoTOx™ with scrubber 3. KnowNOx™ with scrubber 4. Great Southern Flameless Heaters 5. ClearSign 6. Cheng Low NOx	SCR
Refinery Gas Turbines	1. SCR 2. Ammonia Slip Catalyst (ASC) 3. CO Catalyst 4. Dry Low Emissions (DLE or DLN) 5. Cheng Low NOx	SCR
SRU/TGUs	1. SCR 2. LoTOx™ with scrubber 3. KnowNOx™ with scrubber	1. LoTOx™ with WGS 2. SCR
Petroleum Coke Calciner	1. LoTOx™ with scrubber 2. UltraCat with scrubber	1. LoTOx™ with scrubber 2. UltraCat with scrubber
Portland Cement Kilns	1. SCR with or without scrubber 2. UltraCat 3. SNCR	None[4]
Container Glass Melting Furnaces	1. SCR 2. UltraCat	1. SCR 2. UltraCat DGS
Sodium Silicate Furnaces	1. SCR 2. UltraCat	1. SCR 2. UltraCat DGS (without sorbent)
Metal Heat Treating Furnaces	SCR	SCR
ICEs (Non-Refinery/Non-Power Plant)	1. SCR 2. NSCR	SCR

[4] Because of CPCC's current permitting status for their Portland cement kilns (e.g., the permits were surrendered), CPCC operators will not be able to retrofit the Portland cement kilns with air pollution control equipment in response to the proposed project without first dealing with the permitting issues for the cement kilns. Thus, the installation of control technology and the secondary adverse environmental impacts that may be associated with such control technology is not a reasonably foreseeable consequence for CPCC under the present circumstances. Further, there are no other facilities in SCAQMD's jurisdiction that operate Portland cement kilns. Thus, this PEA does not contain an environmental analysis of the control technologies that were originally contemplated in the NOP/IS for the CPCC facility.

Table 2-3 (concluded)
BARCT Control Technology Options for Top NOx Emitting Equipment/Processes

Non-Refinery/Non-Power Plant Gas Turbines	1. SCR 2. Flue Gas Recirculation 3. Staged Combustion/Low NOx Burners 4. Water/Steam Injection 5. Dry Low Emissions (DLE or DLN)	SCR

<u>Selective Catalytic Reduction</u>
Selective Catalytic Reduction (SCR) is post-combustion control equipment that is considered to be BARCT, if cost-effective and feasible, for NOx control of existing combustion sources such as boilers, process heaters, and FCCUs as it is capable of reducing NOx emissions by as much as 95 percent or higher. A typical SCR system design consists of an ammonia storage tank, ammonia vaporization and injection equipment, a booster fan for the flue gas exhaust, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of ammonia and air directly into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor that is replete with catalyst, the catalyst, ammonia, and oxygen (from the air) in the flue gas exhaust reacts primarily (i.e., selectively) with NO and NO_2 to form nitrogen and water in the presence of a catalyst. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. There are two main types of catalysts: one in which the catalyst is coated onto a metal structure and a ceramic-based catalyst onto which the catalyst components are calcified. Commercial catalysts used in SCRs are available in two types of solid, block configurations or modules, plate or honeycomb type, and are comprised of a base material of titanium dioxide (TiO_2) that is coated with either tungsten trioxide (WO_3), molybdic anhydride (MoO_3), vanadium pentoxide (V_2O_5), iron oxide (Fe_2O_3), or zeolite catalysts. These catalysts are used for SCRs because of their high activity, insensitivity to sulfur in the exhaust, and useful life span of approximately five years or more. Ultimately, the material composition of the catalyst is dependent upon the application and flue gas conditions such as gas composition, temperature, et cetera.

For conventional SCRs, the minimum temperature for NOx reduction is 500 ^oF and the maximum operating temperature for the catalyst is 800 ^oF. Depending on the application, the type of fuel combusted, and the presence of sulfur compounds in the exhaust gas, the optimum flue gas temperature of an SCR system is case-by-case and will range between 550 ^oF and 750 ^oF to limit the occurrence of several undesirable side reactions at certain conditions. One of the major concerns with the SCR process is the poisoning of the catalyst due to the presence of sulfur and the oxidation of sulfur dioxide (SO_2) in the exhaust gas to sulfur trioxide (SO_3) and the subsequent reaction between SO_3 and ammonia to form ammonium bisulfate or ammonium sulfate. The formation of either ammonium bisulfate or ammonium sulfate depends on the amount of SO_3 and ammonia present in the flue gas and can cause equipment plugging downstream of the catalyst. The presence of particulates, heavy metals and silica in the flue gas exhaust can also limit catalyst performance.

However, minimizing the quantity of injected ammonia and maintaining the ammonia temperature within a predetermined range will help avoid these undesirable reactions while minimizing the production of unreacted ammonia which is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip can vary between less than five ppmv when the catalyst is fresh and 20 ppmv at the end of the catalyst life.

In addition to the conventional SCR catalysts, there are high temperature SCR catalysts that can withstand temperatures up to 1200 ^{o}F and low temperature SCR catalysts that can operate below 500 ^{o}F.

Further, SCR manufacturers have developed Ammonia Slip Catalyst (ASC) which is a layer of catalyst that is installed downstream of the SCR catalyst to enhance the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The use of ASCs allow for operations at higher NH_3/NOx ratios to ensure complete NOx conversion while maintaining low ammonia slip.

Similar to ASC, CO catalyst is used in conjunction with the SCR catalyst to concurrently reduce NOx to N2 and oxidize CO and hydrocarbon to CO2 and water. CO catalyst is typically made of platinum, palladium or rhodium, and is capable of removing approximately 90 percent of CO and 85 percent to 90 percent of hydrocarbon or hazardous air pollutants from an exhaust stream.

<u>Wet Gas Scrubbers (WGSs)</u>
WGS technology is a multi-pollutant control system that primarily controls SOx and PM emissions but can be installed to function with NOx control equipment. WGSs can be used to control emissions from FCCUs, refinery process heaters and boilers, SRU/TGUs, petroleum coke calciners, and cement kilns. There are two types of wet gas scrubbers: 1) caustic-based non-regenerative WGS; and, 2) regenerative WGS.

In non-regenerative wet gas scrubbing, caustic soda (sodium hydroxide - NaOH) or other alkaline reagents, such as soda ash, are used as an alkaline absorbing reagent (absorbent) to capture SO_2 emissions. The absorbent captures SO_2 and sulfuric acid mist (H_2SO4) and converts it to various types of sulfites and sulfates (e.g., $NaHSO_3$, Na_2SO_3, and Na_2SO_4). The absorbed sulfites and sulfates are later separated by a purge treatment system and the treated water, free of suspended solids, is either discharged or recycled.

One example of the caustic-based non-regenerative scrubbing system is the proprietary Electro Dynamic Venturi (EDV) scrubbing system offered by BELCO Technologies Corporation (see Figure 2-7). An EDV scrubbing system consists of three main modules: 1) a spray tower module; 2) a filtering module; and, 3) a droplet separator module. The flue gas enters the spray tower module, which is an open tower with multiple layers of spray nozzles. The nozzles supply a high density stream of caustic/water solution that is directed in a countercurrent flow to the gas flow and encircles, encompasses, wets, and saturates the flue gas. Multiple stages of liquid/gas absorption occur in the spray tower module and SO_2 and acid mist are captured and converted to sulfites and sulfates. Large particles in the flue gas are also removed by impaction with the water droplets.

The flue gas saturated with heavy water droplets continues to move up the wet scrubber to the filtering module where the flue gas reaches super-saturation. At this point, water continues to condense and the fine particles in the gas stream begin to cluster together, to form larger and heavier groups of particles. Next, the flue gas, super-saturated with heavy water droplets, enters the droplet separator module causing the water droplets to impinge on the walls of parallel spin vanes and drain to the bottom of the scrubber.

The spent caustic/water solution purged from the WGS is later processed in a purge treatment unit. The purge treatment unit contains a clarifier that removes suspended solids for disposal. The effluent from the clarifier is oxidized with agitated air to help convert sulfites to sulfates and also reduce the chemical oxygen demand (COD) so that the effluent can be safely discharged to a wastewater system.

A regenerative WGS removes SO_2 from the flue gas by using a buffer solution that can be regenerated. The buffer is then sent to a regenerative plant where the SO_2 is extracted as concentrated SO_2. The concentrated SO_2 is then sent to a sulfur recovery unit (SRU) to recover the liquid SO_2, sulfuric acid and elemental sulfur as a by-product. When the inlet SO_2 concentrations are high, a substantial amount of sulfur-based by-products can be recovered and later sold as a commodity for use in the fertilizer, chemical, pulp and paper industries. For this reason, the use of a regenerative WGS is favored over a non-regenerative WGS.

One example of a regenerative scrubber is the proprietary LABSORB offered by BELCO Technologies Corporation [5, 6]. The LABSORB scrubbing process uses a patented non-organic aqueous solution of sodium phosphate salts as a buffer. This buffer is made from two common available products, caustic and phosphoric acid. The LABSORB system consists of: 1) a quench pre-scrubber; 2) an absorber; and, 3) a regeneration section which typically includes a stripper and a heat exchanger.

In the scrubbing side of the regenerative scrubbing system, the quench pre-scrubber is used to wash out any large particles that are carried over, plus any acid components in the flue gas such as hydrofluoric acid (HF), hydrochloric acid (HCl), and SO_3. The absorption of SO_2 is carried out in the absorber. The absorber typically consists of one single, high-efficiency packed bed scrubber filled with high-efficiency structural packing material. However, if the inlet SO_2 concentration is low, a multiple-staged packed bed scrubber, or a spray-and-plate tower scrubber, may be used instead to achieve an ultra-low outlet SO_2 concentration.

The third step in the regenerative wet gas scrubbing system is the regenerative section in which the SO_2-rich buffer stream is steam heated to evaporate the water from the buffer. The buffer stream is then sent to a stripper/condenser unit to separate the SO_2 from the buffer. The buffer free of SO_2 is returned to the buffer mixing tank while the condensed-SO_2 gas stream is sent back to the SRU for further treatment.

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[5] *Evaluating Wet Scrubbers,* Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

[6] *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005.

LoTOx™ Application with Wet Gas Scrubber

The LoTOx™ is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. LoTOx™ stands for "Low Temperature Oxidation" process in which ozone (O_3) is used to oxidize insoluble NOx compounds into soluble NOx compounds which can then be removed by absorption in a caustic, lime or limestone solution. The LoTOx™ process is a low temperature application, optimally operating at about 325 ºF.

A typical combustion process produces about 95 percent NO and five percent NO_2. Because both NO and NO_2 are relatively insoluble in an aqueous solution, a WGS alone is not efficient in removing these insoluble compounds from the flue gas stream. However, with a LoTOx™ system and the introduction of O_3, NO and NO_2 can be easily oxidized into a highly soluble compound N_2O_5 (see Reactions 5 and 6) and subsequently converted to nitric acid (HNO_3) (see Reaction 7). Then, in a wet gas scrubber for example, the HNO_3 is rapidly absorbed in caustic (NaOH) (see Reaction 8), limestone or lime solution (see Reactions 9 and 10). In addition, because the rates of oxidizing reactions for NOx (see Reactions 5 and 6) are fast compared to the very slow SO_2 oxidation reaction (see Reaction 11), no ammonium bisulfate ($(NH_4)HSO_4$) or sulfur trioxide (SO_3) is formed.

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 - Fast)
$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$	(Reaction 7)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 - Very slow)

The LoTOx™ process requires a source of oxygen and generates O_3 on site. Typically oxygen (O_2) is stored as a liquid in vacuum-jacketed vessels or is delivered by pipeline. O_3 is an unstable gas and it is typically generated on demand from the O_2 supply using an O_3 generator. An O_3 generator is shaped similar to a shell and tube heat exchanger and uses a corona discharge to dissociate the O_2 molecules into individual atoms so that the individual oxygen atoms combine with each other to form O_3. The LoTOx™ process contains an ozone injection manifold designed to achieve uniform distribution and complete mixing. A ratio of 1.75 parts NOx to 2.5 parts O_3 is needed in order to achieve a NOx conversion and reduction of 90 percent to 95 percent. Since sulfur dioxide (SO_2) is an ozone scavenger because it readily bonds with O_3 to form sulfur trioxide (SO_3), the LoTOx™ process typically has a very low O_3 slip (excess O_3) that ranges from zero ppmv to three ppmv. Figure 2-6 shows a schematic of the O_3 generation process.

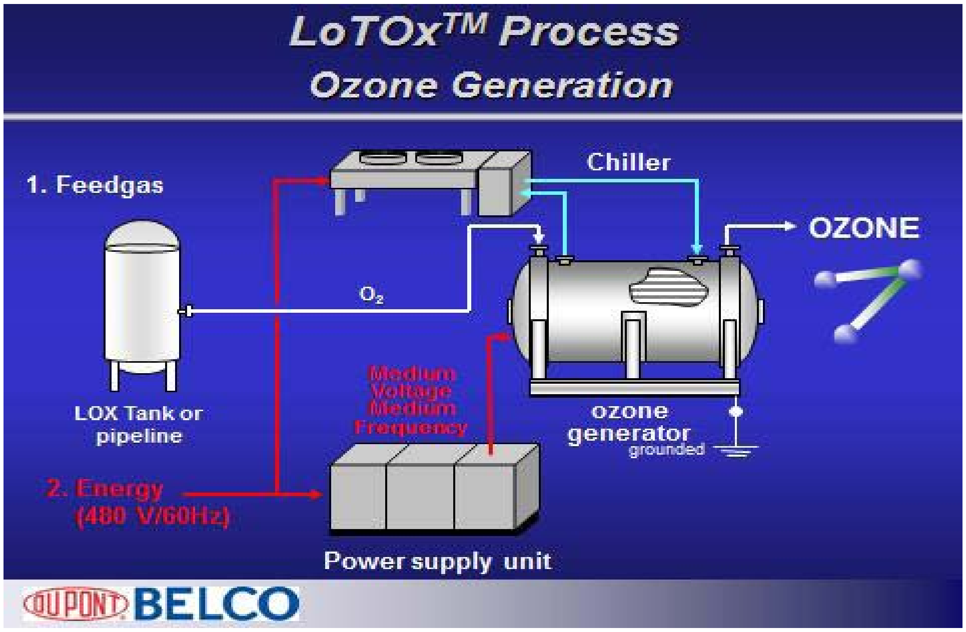

Figure 2-6: Ozone Generation Process

The LoTOx™ process can be integrated with any type of wet scrubbers (e.g., venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs). For example, Linde has engineered more than 24 LoTOx™ applications for EDV™ scrubbers engineered by BELCO since 2007 for refinery FCCU applications. A LoTOx™ system with an EDV™ scrubber is shown in Figure 2-7.

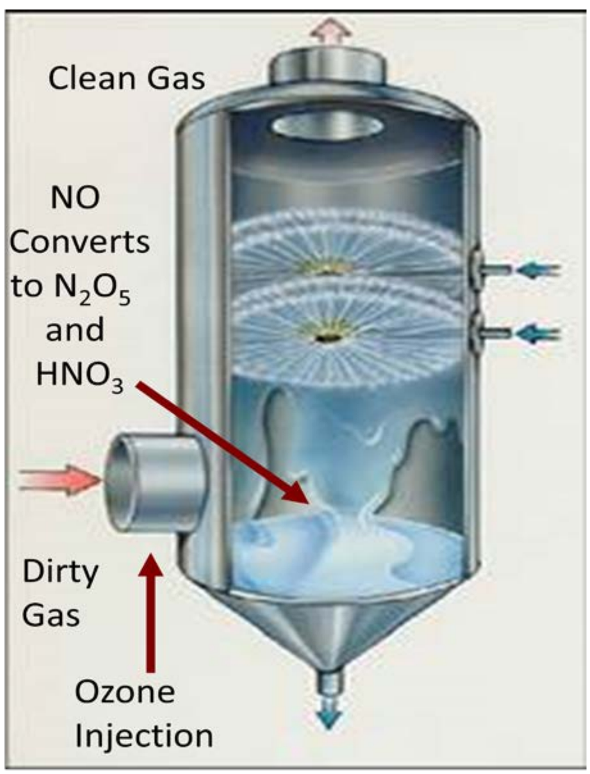

Figure 2-7: EDV Scrubber with LoTOx™ Application

In addition, MECS, BELCO's sister company, has engineered more than two dozen DynaWave scrubbers with LoTOx^{TM} systems specifically designed for refinery SRU/TGUs. Figure 2-8 shows a schematic for a DynaWave scrubber with a LoTOx^{TM} application.

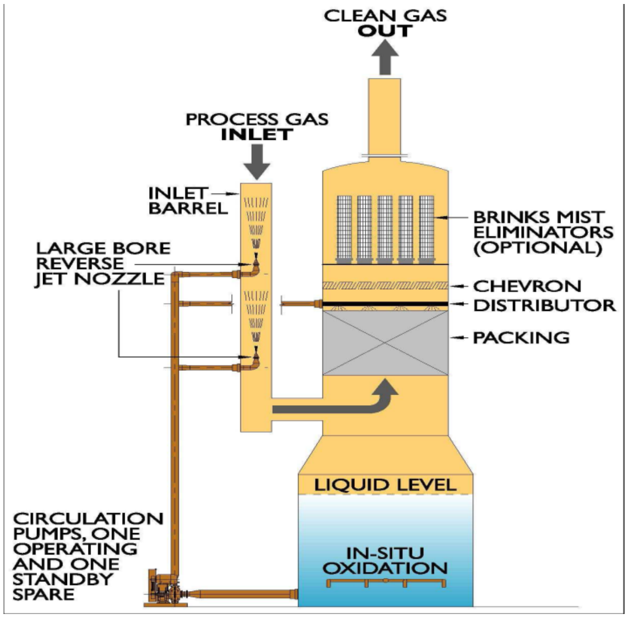

Figure 2-8: DynaWave Scrubber with LoTOx^{TM} Application

When compared to SCR technology, the LoTOx^{TM} application has several advantages, as follows:

- Unlike SCR which operates at high temperatures, LoTOx^{TM} is a low temperature operating system that does not require additional heat input to maintain operational efficiency and enable maximum heat recovery of high temperature combustion gases.
- Unlike SCR which is primarily designed to reduce only NOx, LoTOx^{TM} can be integrally connected to a scrubber (e.g., wet or semi-dry scrubber, or wet electrostatic ESP) and become a multi-component air pollution control system capable of reducing NOx, SOx and PM in one system.
- There is no formation of ammonia slip, SO_3, or $(NH_4)HSO_4$ with the LoTOx^{TM} process.

<u>UltraCat</u>

UltraCat is a commercially available multi-pollutant control technology designed to remove NOx and other pollutants such as SO_2, PM, HCl, Dioxins, and HAPs such as mercury in low temperature applications. UltraCat technology is comprised of filter tubes which are made of fibrous ceramic materials embedded with proprietary catalysts. The optimal operating temperature range of an UltraCat system is approximately 350 ^oF to 750 ^oF. In order to achieve a NOx removal efficiency of approximately 95 percent, aqueous ammonia is injected upstream of the UltraCat filters. In addition, to remove SO_2, HCl, and other acid gases with a removal efficiency ranging from 90 percent to 98 percent, dry sorbent such as hydrated lime, sodium bicarbonate or trona is also injected upstream of the UltraCat filters. UltraCat is also capable of controlling particulates to a level of 0.001 grains per standard cubic foot of dry gas (dscf).

The UltraCat filters are arranged in a baghouse configuration with a low pressure drop such as five inches water column (inH20) across the system. The UltraCat system is equipped with a reverse pulse-jet cleaning action that back flushes the filters with air and inert gas to dislodge the PM deposited on the outside of the filter tubes. Depending on the loading, catalytic filter tubes need to be replaced every five to 10 years. The UltraCat system is shown in Figure 2-9.

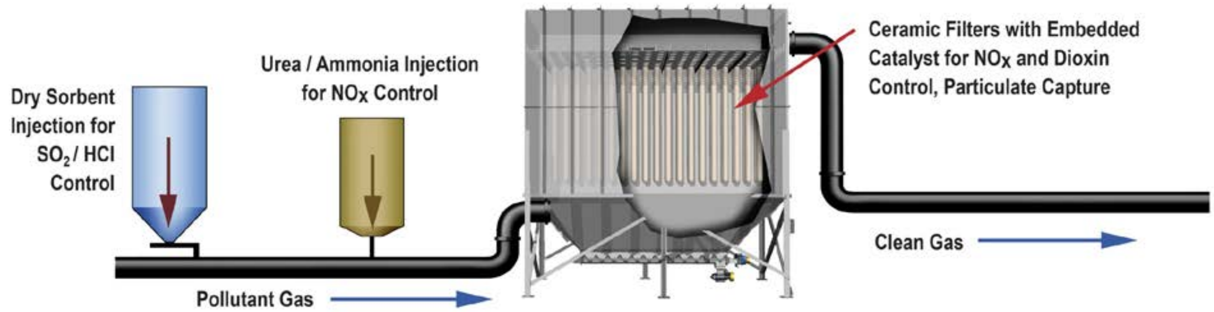

Figure 2-9: UltraCat System

CHAPTER 3

EXISTING SETTING

Introduction

Aesthetics

Air Quality and Greenhouse Gases

Energy

Hazards and Hazardous Materials

Hydrology and Water Quality

Solid and Hazardous Waste

Transportation and Traffic

3.0 INTRODUCTION

In order to determine the significance of the impacts associated with a proposed project, it is necessary to evaluate the project's impacts against the backdrop of the environment as it exists at the time the NOP/IS is published. CEQA Guidelines §15360 defines "environment" as "the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance" (see also Public Resources Code §21060.5). According to CEQA Guidelines §15125 (a), a CEQA document must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the NOP is published from both a local and regional perspective. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant. The description of the environmental setting shall be no longer than is necessary to provide an understanding of the significant effects of the proposed project and its alternatives.

Since this CEQA document is programmatic in nature (e.g., PEA) that covers the SCAQMD's entire jurisdiction, the existing setting for each category of impact is described on a regional level. The following subchapters describe the existing environmental setting for those environmental areas identified in the NOP/IS (see Appendix E) that may be adversely affected by the proposed project. These areas include the following topics: aesthetics; air quality and GHGs; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic.

SUBCHAPTER 3.1

AESTHETICS

Regulatory Setting

Environmental Setting

3.1 AESTHETICS

This subchapter contains an overview of existing aesthetic resources, including scenic highways and coastal zones within the District.

3.1.1 Regulatory Setting

3.1.1.1 Federal

Aesthetic resources on federal lands are managed by the federal government using various visual resource management programs, depending on the type of federal land and/or the federal agency involved with a given project. Examples of federal visual resource management programs include the Visual Resource Management System utilized by the Federal Bureau of Land Management (BLM) and the Visual Management System utilized by the United States Forest Service (USFS).

3.1.1.2 State

California Coastal Act

The California Coastal Act of 1976 was enacted to regulate development projects within California's Coastal Zone. The act includes requirements that protect views and aesthetic resources through siting and design control measures, which are typically implemented at the local planning level through local coastal programs (LCPs) or land use plans (LUPs). According to the California Coastal Act:

> *The scenic and visual qualities of coastal areas shall be considered and protected as a resource of public importance. Permitted development shall be sited and designed to protect views to and along the ocean and scenic coastal areas, to minimize the alteration of natural land forms, to be visually compatible with the character of surrounding areas, and, where feasible, to restore and enhance visual quality in visually degraded areas. New development in highly scenic areas such as those designated in the California Coastline Preservation and Recreation Plan prepared by the Department of Parks and Recreation and by local government shall be subordinate to the character of its setting (Public Resources Code. California Coastal Act [Chapter 3 (Coastal Resources Planning and Management Policies) Article 6, §30251]).*

For local jurisdictions that do not have an approved LCP, regulation of development projects within the coastal zone remains under the jurisdiction of the California Coastal Commission (CCC).

State Scenic Highway Program

California's Scenic Highway Program was created by the California Legislature in 1963 to preserve and protect scenic highway corridors from change that would diminish the aesthetic value of land adjacent to those highways. When a city or county nominates an eligible scenic highway for official designation, it must adopt ordinances to preserve the scenic quality of the corridor or document such regulations that already exist in various portions of local codes. These ordinances make up the scenic corridor protection program.

Scenic corridor protection programs include policies intended to preserve the scenic qualities of the highway corridor, including regulation of land use and density of development, detailed land and site planning, control of outdoor advertising (including a ban on billboards), careful attention to and control of earthmoving and landscaping, and careful attention to design and appearance of structures and equipment (California Streets and Highways Code §260 et seq.).

3.1.1.3 Local

<u>Counties and Cities</u>

The geographic area encompassed by the District includes numerous cities and unincorporated communities in the counties of Los Angeles, Orange, San Bernardino, and Riverside. Each of these counties and incorporated cities has prepared a general plan, which is the primary document that establishes local land use policies and goals. Many of these general plans also establish local policies related to aesthetics and the preservation of scenic resources within their communities or subplanning areas, and may include local scenic highway programs.

<u>Local Coastal Programs</u>

The CCC and the local governments along the coast share responsibility for managing the state's coastal resources. Through coordination with the CCC, coastal cities and counties develop LCPs. These programs are the primary means for carrying out the policies of the California Coastal Act at the local level. In general, these policies are intended to promote public access and enhance recreational use of the coast as well as protection of natural resources in the coastal zone. Examples of counties, cities and local jurisdictions within the District that do have an approved LCP or LUP include Los Angeles County and the County of Orange and the cities of Santa Monica, El Segundo, Manhattan Beach, Hermosa Beach, Redondo Beach, Palos Verdes Estates, Rancho Palos Verdes, Long Beach, Avalon, Huntington Beach, Newport Beach, Irvine, Laguna Beach, Laguna Niguel, Dana Point, and San Clemente.

Following approval by the CCC, an LCP is certified and the local governments implement the programs. LCPs include two main components, a Land Use Plan and an Implementation Plan. These components may include policies or regulations that apply to preservation of visual and scenic resources within the coastal zone. Typically, these policies relate to preservation of views of the coast.

3.1.2 Environmental Setting

This environmental setting subchapter describes the aesthetics resources settings that may be adversely affected by the proposed project. Specifically, this environmental setting subchapter describes visual character and quality, visual resources, scenic highways, and coastal zones within the District.

3.1.2.1 Visual Character and Quality

Visual character and quality are defined by the built and natural environment. The ***visual character*** of a view is descriptive cataloguing of underlying landforms and landcover including the topography, general land use patterns, scale, form, and the presence of natural areas. Urban features, such as structures, roads, utility lines, and other development associated with human activities also help to define visual character. ***Visual quality*** is an evaluative appraisal of the aesthetics of a view and is established using a well-established approach to visual analysis adopted from the Federal Highway Administration (FHWA) based upon the relative degree of vividness, intactness, and unity found within the visual setting, as defined in the following bullet points (FHWA, 1981).

- Vividness is the visual power or memorability of landscape components as they combine in striking and distinctive patterns.
- Intactness is the visual integrity of the landscape and its freedom from encroaching elements; this factor can be present in well-kept urban and rural landscapes, as well as in natural settings.
- Unity is the degree to which the visual resources of the landscape join together to form a coherent, harmonious visual pattern. Unity refers to the compositional harmony or inter-compatibility between landscape elements.

Each of the three criteria is independent and intended to evaluate one aspect of visual quality; however, no one criterion considered alone equates to visual quality.

The perception of visual quality can vary significantly among viewers depending on their level of visual sensitivity (interest). Sensitive viewers' perceptions can vary seasonally and even hourly as weather, light, shadow, and the elements that compose the viewshed change. Form, line, color, and texture are the basic components used to describe visual character and quality for most visual assessments (FHWA, 1981). Sensitivity depends upon the length of time the viewer has access to a particular view. Typically, residential viewers have extended viewing periods and are often concerned about changes in views from their homes. Visual sensitivity is, therefore, considered to be high for neighborhood residential areas. Visual sensitivity is considered to be less important for commuters and other people driving along surrounding streets. Views from vehicles are generally more fleeting and temporary, yet under certain circumstances are sometimes considered important (e.g., viewers who are driving for pleasure, views/vistas from scenic corridors).

As discussed in the Subchapter 3.1 - Aesthetics, of the Final Program Environmental Impact Report (PEIR) prepared for the Southern California Association of Governments (SCAG) 2012-2035 Regional Transportation Plan/Sustainable Communities Strategy (RTP/SCS)[1], various jurisdictions within the SCAG region, which includes the jurisdiction of SCAQMD such as cities, counties, and federal or regional agencies, provide guidelines regarding the

[1] SCAG, Final PEIR for the 2012-2035 RTP/SCS, SCH# 2011051018; April 4, 2012. http://rtpscs.scag.ca.gov/Pages/Final-2012-PEIR.aspx

preservation and enhancement of visual quality in their plans or regulations[2]. An example of such guidance can be found in Caltrans Scenic Highway Guidelines which contains examples of visual intrusions[3], which are presented in Table 3.1-1. As the table illustrates, a given visual element may be considered desirable or undesirable, depending on design, location, use, and other considerations. Because of the size and diversity of the area within the SCAQMD's jurisdiction, it is not possible to apply uniform standards to all areas within the District.

TABLE 3.1-1

Caltrans Scenic Highway Guidelines – Examples of Visual Intrusions

Minor Intrusion	Moderate Intrusion	Major Intrusion
Buildings: *Residential, Commercial, and Industrial Developments*		
Widely dispersed buildings. Natural landscape dominates. Wide setbacks and buildings screened from roadway. Forms, exterior colors and materials are compatible with landscape. Buildings have cultural or historical significance.	Increased numbers of buildings, not well integrated into the landscape. Smaller setbacks and lack of roadway screening. Buildings do not dominate the landscape or obstruct scenic view.	Dense and continuous development. Highly reflective surfaces. Buildings poorly maintained. Visible blight. Development along ridgelines. Buildings dominate the landscape or obstruct scenic view.
Unsightly Land Uses: *Dumps, Quarries, Concrete Plants, Tank Farms, Auto Dismantling*		
Screened from view so that most of facility is not visible from the highway.	Not screened and visible but programmed/funded for removal and site restoration. Land use is visible but does not dominate the landscape or obstruct scenic view.	Not screened and visible by motorists. Will not be removed or modified. Land use dominates the landscape or obstructs scenic view.
Commercial Retail Development		
N/A	Neat and well landscaped. Single story. Generally blends with surroundings. Development is visible but does not dominate the landscape or obstruct scenic view.	Not harmonious with surroundings. Poorly maintained or vacant. Blighted. Development dominates the landscape or obstructs scenic view.

[2] California cities and counties are not required to include visual quality elements in their General Plans although many do. However, the General Plans are required to include a Conservation Element, which includes resources such as waterways and forests that frequently are also scenic resources.

[3] Caltrans, Scenic Highway Guidelines - Appendix E, October 2008; (Caltrans, 2008). http://www.dot.ca.gov/hq/LandArch/scenic/guidelines/scenic_hwy_guidelines_04-12-2012.pdf

TABLE 3.1-1 (Continued)
Caltrans Scenic Highway Guidelines – Examples of Visual Intrusions

Minor Intrusion	Moderate Intrusion	Major Intrusion
	Parking Lots	
Screened from view so that most of the vehicles and pavement are not visible from the highway.	Neat and well landscaped. Generally blends with surroundings. Pavement and/or vehicles visible but do not dominate the landscape or degrade scenic view.	Not screened or landscaped. Pavement and/or vehicles dominate the landscape or degrade scenic view.
	Off-Site Advertising Structures	
N/A	N/A	Billboards degrade or obstruct scenic view.
	Noise Barriers	
N/A	Noise barriers are well landscaped and complement the natural landscape. Noise barriers do not degrade or obstruct scenic view.	Noise barriers degrade or obstruct scenic view.
	Power Lines and Communication Facilities	
Not easily visible from road.	Visible, but do not dominate scenic view.	Towers, poles or lines dominate view. Scenic view is degraded.
	Agriculture: *Structures, Equipment, Crops*	
Generally blends in with scenic view. Is indicative of regional culture.	Not compatible with the natural landscape. Scale and appearance of structures and equipment visually competes with natural landscape.	Scale and appearance of structures and equipment are incompatible with and dominates natural landscape. Structures, equipment or crops degrade or obstruct scenic view.
	Exotic Vegetation	
Used as screening and landscaping. Generally is compatible with scenic view.	Competes with native vegetation for visual dominance.	Incompatible with and dominates natural landscape. Scenic view is degraded.
	Clearcutting	
N/A	Clearcutting or deforestation is evident, but is in the distant background.	Clearcutting or deforestation is evident. Scenic view is degraded.
	Erosion	
Minor soil erosion (i.e., rill erosion).	Rill erosion starting to form gullies.	Large slip outs and/or gullies with little or no vegetation. Scenic view is degraded.

TABLE 3.1-1 (Concluded)
Caltrans Scenic Highway Guidelines – Examples of Visual Intrusions

Minor Intrusion	Moderate Intrusion	Major Intrusion
Grading		
Grading generally blends with adjacent landforms and topography.	Some changes, less engineered appearance and restoration are taking place.	Extensive cut and fill. Unnatural appearance, scarred hillsides or steep slopes with little or no vegetation. Canyons filled in. Scenic view is degraded.
Road Design		
Blends in and complements scenic view. Roadway structures are suitable for location and compatible with landscape.	Large cut and fill slopes are visible. Scale and appearance of roadway, structures, and appurtenances are incompatible with landscape.	N/A

Source: Caltrans, 2008

The *viewshed* can be defined as all of the surface area visible from a particular location or sequence of locations, and is described in terms of the dominance of landforms, landcover, and manmade development constituting visual character. Views of high visual quality in urban settings generally have several of the following additional characteristics:

- Harmony in scale with the surroundings;
- Context sensitive architectural design; and,
- Impressive landscape design features.

Areas of medium visual quality have interesting forms but lack unique architectural design elements or landscape features. Areas of low visual quality have uninteresting features and/or undistinguished architectural design and /or other common elements.

3.1.2.2 Visual Resources

Visual resources include historic buildings that uniquely identify a setting, views identified as significant in local plans, and/or views from scenic highways. The importance of a view to viewers is related to the position of the viewers relative to the resource and the distinctiveness of a particular view. The visibility and visual dominance of landscape elements are usually described with respect to their placement in the viewshed.

Visual resources occur in a diverse array of environments within the boundaries of the District, ranging in character from urban centers to rural agricultural land, natural woodlands, and coastal views. The extraordinary range of visual features in the region is afforded by the mixture of climate, topography, flora, and fauna found in the natural environment, and the diversity of style, composition, and distribution of the built environment. Views of the coast from locations in Los Angeles and Orange counties are considered valuable visual resources, while views of various mountain ranges are prevalent throughout the District. Other natural features that may be visually significant in the District include rivers, streams, creeks, lakes, and reservoirs.

The Los Angeles County Draft 2014 General Plan 2035[4] identifies regional open space and recognized scenic areas, generally including the Santa Monica Mountains, as well as the San Gabriel Mountains, Verdugo Hills, Santa Susana Mountains, Simi Hills, Santa Monica Mountains, and Puente Hills. In addition, ridgelines and hillsides are generally considered to be scenic resources, with specific measures for the protection of these areas (LA County, 2014).

The Orange County General Plan[5] identifies the Santa Ana Mountains along with their distinctive twin peaks known as "Saddleback" as the county's signature landmark. The Plan designates 10 scenic "viewscape corridors," which include among others Pacific Coast Highway, Oso Parkway, Ortega Highway, Jamboree Road, Santiago Canyon Road, and Laguna Canyon Road. These designated viewscape corridors provide scenic views of the Santa Ana Mountains, Lomas de Santiago and the San Joaquin Hills, as well as numerous canyons and valleys including the Santa Ana Canyon, Capistrano Valley, Laguna, Aliso, Wood, Moro, San Juan, Trabuco Santiago, Modjeska, Silverado, Limestone, and Black Star Canyons. Finally, the General Plan identifies nearly 42 miles of coastline and approximately 33 miles of sandy beaches as defining scenic resources (Orange County, 2011).

The Riverside County General Plan[6] identifies regional scenic resources, including Santa Ana River basin, Lake Mathews, Lake Perris, Lake Elsinore, Lake Skinner, Vail Lake, the San Jacinto River, Murrieta Creek, the Santa Margarita River, the vineyard/citrus region near Temecula, the Diamond Valley Reservoir, Joshua Tree National Park, Whitewater River, the Santa Rosa Mountains, and a portion of the Salton Sea (Riverside County, 2014).

The County of San Bernardino 2007 General Plan[7] identifies several scenic areas, including the San Gabriel Mountains, the San Bernardino Mountains, La Loma Hills, Jurupa Hills, Chino Hills, Yucaipa Hills, Holcomb Valley, and the Mojave Desert. In addition, Big Bear Lake, Silverwood Lake, Lake Arrowhead, and Lake Gregory, along with associated waterways, serve as defining characteristics of the mountain regions within the County. San Bernardino County has a wide variety of scenic and wilderness areas respectively categorized as the Mountain, Valley, and Desert regions. Each region has its own defined measures for protecting the specific resources contained in this region. The County of San Bernardino also considers desert night-sky views to be scenic resources and has enacted measures to reflect this (San Bernardino County, 2014).

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[4] Los Angeles County, 2014, 2014 Draft General Plan 2035, July 2014. http://planning.lacounty.gov/generalplan/draft2014

[5] Orange County, 2011, Orange County General Plan 2005, March 2011; (Orange County, 2011). http://ocplanning.net/planning/generalplan2005

[6] Riverside County, 2014. Riverside County General Plan, March 2014. http://planning.rctlma.org/ZoningInformation/GeneralPlan.aspx

[7] San Bernardino County, 2014. County of San Bernardino 2007 General Plan, last amended April 2014. http://www.sbcounty.gov/Uploads/lus/GeneralPlan/FINALGP.pdf

In addition to County plans, many of the cities within the District have general plan policies, and in some cases, ordinances, related to the protection of visual resources. In addition to the visual resources related to natural areas, many features of the built environment that may also have visual significance include individual or groups of structures that are distinctive due to their aesthetic, historical, social, or cultural significance or characteristics, such as architecturally appealing buildings or groups of buildings, landscaped freeways, bridges or overpasses, and historic resources.

3.1.2.3 Scenic Highways

Within the District, there are numerous officially designated state and county scenic highways and one historic parkway, as listed in Table 3.1-2.

There are also a number of roadways that have been determined eligible for state scenic highway designation, as listed in Table 3.1-3.

TABLE 3.1-2
Scenic Highways Within District Borders

Route	County	Location	Description	Miles	Designation
2	Los Angeles	From near La Cañada Flintridge north to the San Bernardino County line.	This U.S. Forest Service Scenic Byway and State Scenic Highway winds along the spine of the San Gabriel Mountains. It provides views of the mountain peaks, the Mojave Desert, and the Los Angeles Basin.	55	ODSSH[(a)]
38	San Bernardino	From east of South Fork Campground to State Lane.	This U.S. Forest Service Scenic Byway and State Scenic Highway crosses the San Bernardino Mountains at Onyx Summit. It features forested mountainsides with far-off desert vistas near the summit.	16	ODSSH
62	Riverside	From I-10 north to the San Bernardino County line.	This highway features high desert country scenery and leads to or from Joshua Tree National Monument. Large “windmill farms,” where wind power is used to generate electricity, can be seen along the way.	9	ODSSH

TABLE 3.1-2 (Continued)
Scenic Highways Within District Borders

Route	County	Location	Description	Miles	Designation
74	Riverside	From west boundary of the San Bernardino National Forest to SR-111 in Palm Desert.	This road goes from the southern Mojave Desert to oak and pine forests of San Bernardino National Forest. It offers views of the San Jacinto Valley and peaks of the San Jacinto Mountains.	48	ODSSH
91	Orange	From SR-55 to east of Anaheim city limit.	This freeway runs along the banks of the Santa Ana River. Views include residential and commercial development with intermittent riparian and chaparral vegetation.	4	ODSSH
243	Riverside	From SR-74 to the Banning city limit.	This U.S. Forest Service Scenic Byway and State Scenic Highway traverses forested mountain scenery along a ridge of the San Bernardino Mountains. It then drops in a series of switchbacks offering views of the San Bernardino Valley and the desert scenery.	28	ODSSH
N/A	Los Angeles	Mulholland Highway from SR- 1 to Kanan Dume Road and from west of Cornell Road to east of Las Virgenes Road.	With the dramatic canyons, oak woodlands, open spaces and ocean views of the Santa Monica Mountains, Mulholland Highway offers travelers views of the mountains, the Pacific Ocean, and historic sites along its stretch.	19	ODCSH[(b)]
N/A	Los Angeles	Malibu Canyon- Las Virgenes Highway from State Route 1 to Lost Hills Road.	The rugged terrain and ancient rock formations along this route have been a backdrop of many early California settlers. The formations have known presence dating to the original De Anza expedition of Spanish colonists.	7.4	ODCSH

Source: Caltrans, Officially Designated State Scenic Highways, accessed August 2014. http://www.dot.ca.gov/hq/LandArch/scenic/schwy.htm
(a) ODSSH = Officially Designated State Scenic Highway
(b) ODCSH = Officially Designated County Scenic Highway

TABLE 3.1-3
Highways Within District Boundaries Eligible for State Scenic Highway Designation

Route	County	Location (From/To)	Postmiles
1	Orange/LA	I-5 south of San Juan Capistrano/SR-19 near Long Beach	0.0-3.6
1	LA/(Ventura)	SR-187 near Santa Monica/SR-101 near El Rio	32.2-21.1
2	LA/SBD	SR-210 in La Cañada Flintridge/SR 138 via Wrightwood	22.9-6.36
5	(SD)/Orange	Opposite Coronado/SR-74 near San Juan Capistrano	R14.0-9.6
5	LA	I-210 near Tunnel Station/SR-136 near Castaic	R44.0-R55.5
10	SBD/Riverside	SR-38 near Redlands/SR-62 near Whitewater	T0.0-R10.0
15	(SD)/Riverside	SR-76 near San Luis Rey River/SR-91 near Corona	R46.5-41.5
15	SBD	SR-58 near Barstow/SR-127 near Baker	76.9-R136.6
18	SBD	SR-138 near Mt. Anderson/SR-247 near Lucerne Valley	R17.7-73.8
27	LA	SR-1/Mulholland Drive	0.0-11.1
30	SBD	SR-330 near Highland/I-10 near Redlands	T29.5-33.3
38	SBD	I-10 near Redlands/SR-18 near Fawnskin	0.0-49.5
39	LA	SR-210 near Azusa/SR-2	14.1-44.4
40	SBD	Barstow/Needles	0.0-154.6
57	Orange/LA	SR-90/SR-60 near City of Industry	19.9-R4.5
58	(Kern)/SBD	SR-14 near Mojave/I-15 near Barstow	112.0-R4.5
62	Riverside/SBD	I-10 near Whitewater/Arizona State Line	0.0-142.7
71	Riverside	SR-91 near Corona/SR-83 north of Corona	0.0-G3.0
74	Orange/Riverside	I-5 near San Juan Capistrano/I-111 (All)	0.0-R96.0
79	(SD)/Riverside	SR-78 near Santa Ysabel/SR-371 near Aguanga	20.2-2.3
91	Orange/Riverside	SR-55 near Santa Ana Canyon/I-15 near Corona	R9.2-7.5
101	LA/(Ventura)/ (SBar)/(SLO)	SR-27 (Topanga Canyon Blvd)/SR-46 near Paso Robles	25.3-57.9
111	(Imperial)/ Riverside	Bombay Beach-Salton Sea/SR-195 near Mecca	57.6-18.4
111	Riverside	SR-74 near Palm Desert/I-10 near Whitewater	39.6-R63.4
118	(Ventura)/LA	SR-23/Desoto Avenue near Browns Canyon	17.4-R2.7
126	(Ventura)/LA	SR-150 near Santa Paula/I-5 near Castaic	R12.0-0R5.8
127	SBD/(Inyo)	I-15 near Baker/Nevada State Line	L0.0-49.4
138	SBD	SR-2 near Wrightwood/SR-18 near Mt. Anderson	6.6-R37.9
142	SBD	Orange County Line/Peyton Drive	0.0-4.4
173	SBD	SR-138 near Silverwood Lake/SR-18 south of Lake Arrowhead	0.0-23.0
210	LA	I-5 near Tunnel Station/SR-134	R0.0-R25.0
215	Riverside	SR-74 near Romoland/SR-74 near Perris	23.5-26.3
243	Riverside	SR-74 near Mountain Center/I-10 near Banning	0.0-29.7
247	SBD	SR-62 near Yucca Valley/I-15 near Barstow	0.0-78.1
330	SBD	SR-30 near Highland/SR-18 near Running Springs	29.5-44.1

Source: Caltrans, Eligible and Officially Designated Routes, accessed August 2014. http://www.dot.ca.gov/hq/LandArch/scenic/cahisys.htm

LA = Los Angeles SBD = San Bernardino SD = San Diego SBar = Santa Barbara
SLO = San Luis Obispo SR = State Route ( ) = County not within the District

3.1.2.4 Coastal Zones

According to the California Coastal Act of 1976, a coastal zone is the land and water area of the State of California from the Oregon border to the border of Mexico, extending seaward to the state's outer limit of jurisdiction, including all offshore islands, and extending inland generally 1,000 yards from the mean high tide line of the sea. In significant coastal estuarine, habitat, and recreational areas, the coastal zone extends inland to the first major ridgeline paralleling the sea or five miles from the mean high tide line of the sea, whichever is less, and in developed urban areas the coastal zone generally extends inland less than 1,000 yards.

The coastal zone within the District generally extends from Leo Carrillo State Park in Malibu in the northwestern corner of Los Angeles County to San Clemente Beach in San Clemente near the southern tip of Orange County.

Local Coastal Plans (LCPs) typically contain policies on visual access and site development review. LCPs are basic planning tools used by local governments to guide development in the coastal zone, in partnership with the California Coastal Commission. LCPs contain the ground rules for future development and protection of coastal resources in the 75 coastal cities and counties. The LCPs specify appropriate location, type, and scale of new or changed uses of land and water. Each LCP includes a land use plan and measures to implement the plan (such as zoning ordinances). Prepared by local government, these programs govern decisions that determine the short- and long-term conservation and use of coastal resources. While each LCP reflects unique characteristics of individual local coastal communities, regional and statewide interests and concerns must also be addressed in conformity with Coastal Act goals and policies.

SUBCHAPTER 3.2

AIR QUALITY AND GREENHOUSE GASES

Criteria Air Pollutants

Non-Criteria Air Pollutants

3.2 AIR QUALITY AND GREENHOUSE GASES

This subchapter provides an overview of the existing air quality setting for each criteria pollutant and their precursors, as well as the human health effects resulting from exposure to these pollutants. In addition, this subchapter includes a discussion of non-criteria pollutants such as TACs and GHGs, and climate change.

3.2.1 Criteria Air Pollutants and Identification of Health Effects

It is the responsibility of the SCAQMD to ensure that state and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, carbon monoxide (CO), nitrogen dioxide (NO2), PM10, PM2.5, sulfur dioxide (SO2), and lead. These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. The California standards are commonly more stringent than the federal standards and in the case of PM10 and SO2, far more stringent. California has also established standards for sulfates, visibility reducing particles, hydrogen sulfide, and vinyl chloride. SCAQMD also has a general responsibility pursuant to Health & Safety Code (HSC) §41700 to control emissions of air contaminants and prevent endangerment to public health.

3.2.1.1 Regional Baseline

Air quality in the area of the SCAQMD's jurisdiction has shown substantial improvement over the last three decades. Nevertheless, some federal and state air quality standards are still exceeded frequently and by a wide margin. Of the National Ambient Air Quality Standards (NAAQS) established for seven criteria pollutants (ozone, CO, NO2, PM10, PM2.5, SO2, and lead), the area within the SCAQMD's jurisdiction is only in attainment with CO, SO2, PM10 and the annual NO2 standards. The SCAQMD is designated as unclassifiable/attainment for the hourly NO2 standard. The EPA intends to redesignate areas after sufficient air quality data are available.

Recent air quality data shows the 1997 PM2.5 standard (15 $\mu g/m^3$) is being met, but falls short in attaining the 2012 annual PM2.5 standard of 12 $\mu g/m^3$. Recent monitoring data also shows that the 2006 24-hour NAAQS for PM2.5 will not be achieved by 2015, due partially to drought conditions and to excessive emissions. The upcoming 2016 AQMP will evaluate PM2.5 emissions and possible control measures to attain the 2006 and 2012 standards by 2019 - 2025. The 2016 AQMP will also demonstrate attainment of the 2008 8-hour ozone standard (75 ppb) by year 2032, and provide an update to the previous 1997 8-hour standard (80 ppb) to be met by 2023. The 2016 AQMP must be submitted to the USEPA by July 20, 2016.

In 2010, a portion of Los Angeles County was designated as not attaining the NAAQS of 0.15 $\mu g/m^3$ for lead. SCAQMD identified two large lead-acid battery recycling facilities as possible sources of lead. One of the facilities was the main contributor to the area's nonattainment status. In response to the nonattainment designation, the State submitted the *Final 2012 Lead State Implementation Plan – Los Angeles County* to the USEPA on June

20, 2012. The plan outlines steps that will bring the area into attainment with the standard. As of February 11, 2014, the USEPA announced in the Federal Register (FR) final approval of the lead air quality plan, effective 30 days after publication (e.g., March 12, 2014).

The state and national ambient air quality standards for each of these pollutants and their effects on health are summarized in Table 3.2-1. The SCAQMD monitors levels of various criteria pollutants at 36 monitoring stations. The 2013 air quality data from SCAQMD's monitoring stations are presented in Table 3.2-2 for ozone, CO, NO2, PM10, PM2.5, SO2, lead and PM10 sulfate.

TABLE 3.2-1

State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard [a)]	Federal Primary Standard [b)]	Most Relevant Effects
Ozone (0_3)	1-hour	0.090 ppm (180 μg/m^3)	No Federal Standard	a) Short-term exposures: 1) Pulmonary function decrements and localized lung edema in humans and animals; and, 2) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; b) Long-term exposures: Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; c) Vegetation damage; and, d) Property damage.
	8-hour	0.070 ppm (137 μg/m^3)	0.075 ppm (147 μg/m^3)	
Suspended Particulate Matter (PM10)	24-hour	50 μg/m^3	150 μg/m^3	a) Excess deaths from short-term exposures and exacerbation of symptoms in sensitive patients with respiratory disease; and, b) Excess seasonal declines in pulmonary function, especially in children.
	Annual Arithmetic Mean	20 μg/m^3	No Federal Standard	
Fine Particulate Matter (PM2.5)	24-hour	No State Standard	35 μg/m^3 [c)]	a) Increased hospital admissions and emergency room visits for heart and lung disease; b) Increased respiratory symptoms and disease; and, c) Decreased lung functions and premature death.
	Annual Arithmetic Mean	12 μg/m^3	12 μg/m^3	

TABLE 3.2-1 (continued)
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard a)	Federal Primary Standard b)	Most Relevant Effects
Carbon Monoxide (CO)	1-Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	a) Aggravation of angina pectoris and other aspects of coronary heart disease; b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; c) Impairment of central nervous system functions; and, d) Possible increased risk to fetuses.
	8-Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
Nitrogen Dioxide (NO_2)	1-Hour	0.180 ppm (339 µg/m^3)	100 ppb d) (188 µg/m^3)	a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; and, c) Contribution to atmospheric discoloration.
	Annual Arithmetic Mean	0.030 ppm (57 µg/m^3)	0.053 ppm (100 µg/m^3)	
Sulfur Dioxide (SO_2)	1-Hour	0.250 ppm (655 µg/m^3)	75 ppb e) (196 µg/m^3)	Broncho-constriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in persons with asthma.
	24-Hour	0.040 ppm (105 µg/m^3)	No Federal Standard	
Sulfate	24-Hour	25 µg/m^3	No Federal Standard	a) Decrease in ventilatory function; b) Aggravation of asthmatic symptoms; c) Aggravation of cardio-pulmonary disease; d) Vegetation damage; e) Degradation of visibility; and, f) Property damage.
Hydrogen Sulfide (H_2S)	1-Hour	0.030 ppm (42 µg/m^3)	No Federal Standard	Odor annoyance.
Lead (Pb)	30-Day Average	1.5 µg/m^3	No Federal Standard	a) Increased body burden; and b) Impairment of blood formation and nerve conduction.
	Rolling 3-Month Average	No State Standard	0.150 µg/m^3	
Visibility Reducing Particles	8-Hour	Extinction coefficient of 0.23 per kilometer - visibility of ten miles or more due to particles when relative humidity is less than 70 percent.	No Federal Standard	The State standard is a visibility based standard not a health based standard and is intended to limit the frequency and severity of visibility impairment due to regional haze. Nephelometry and AISI Tape Sampler; instrumental measurement on days when relative humidity is less than 70 percent.

TABLE 3.2-1 (concluded)
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard [a)]	Federal Primary Standard [b)]	Most Relevant Effects
Vinyl Chloride	24-Hour	0.010 ppm ($26\ \mu g/m^3$)	No Federal Standard	Highly toxic and a known carcinogen that causes a rare cancer of the liver.

a) The California ambient air quality standards for O3, CO, SO2 (1-hour and 24-hour), NO2, PM10, and PM2.5 are values not to be exceeded. All other California standards shown are values not to be equaled or exceeded.

b) The NAAQS, other than O3 and those based on annual averages, are not to be exceeded more than once a year. The O3 standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standards is equal to or less than one.

c) The federal 24-hour PM2.5 standard is 35 $\mu g/m^3$ (98th percentile concentration).

d) The federal one-hour NO2 standard is 100 ppb or 0.100 ppm (98th percentile concentration).

e) The federal one-hour SO2 standard is 75 ppb or 0.075 ppm (99th percentile concentration).

KEY: ppb = parts per billion parts of air, by volume; ppm = parts per million parts of air, by volume; $\mu g/m^3$ = micrograms per cubic meter; mg/m^3 = milligrams per cubic meter

TABLE 3.2-2
2013 Air Quality Data for SCAQMD

CARBON MONOXIDE (CO) [a]			
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. ppm, 8-hour
LOS ANGELES COUNTY			
1	Central Los Angeles	330	2.0
2	Northwest Coastal Los Angeles County	340	1.3
3	Southwest Coastal Los Angeles County	281*	2.5
4	South Coastal Los Angeles County 1	249*	2.0
4	South Coastal Los Angeles County 2	--	--
4	South Coastal LA County 3	323	2.6
6	West San Fernando Valley	323	2.3
7	East San Fernando Valley	335	2.4
8	West San Gabriel Valley	201*	1.7
9	East San Gabriel Valley 1	343	1.7
9	East San Gabriel Valley 2	347	0.8
10	Pomona/Walnut Valley	340	1.6
11	South San Gabriel Valley	347	2.0
12	South Central Los Angeles County	338	3.5
13	Santa Clarita Valley	352	0.8
ORANGE COUNTY			
16	North Orange County	355	2.2
17	Central Orange County	333	2.6
18	North Coastal Orange County	313	2.0
19	Saddleback Valley	356	1.3
RIVERSIDE COUNTY			
22	Norco/Corona	--	--
23	Metropolitan Riverside County 1	334	2.0
23	Metropolitan Riverside County 2	318	1.6
23	Mira Loma	339	1.9
24	Perris Valley	--	--
25	Lake Elsinore	336	0.6
26	Temecula	--	--
29	Banning Airport	--	--
30	Coachella Valley 1**	354	1.5
30	Coachella Valley 2**	--	--
SAN BERNARDINO COUNTY			
32	Northwest San Bernardino Valley	340	1.7
33	Southwest San Bernardino Valley	--	--
34	Central San Bernardino Valley 1	337	1.3
34	Central San Bernardino Valley 2	340	1.7
35	East San Bernardino Valley	--	--
37	Central San Bernardino Mountains	--	--
38	East San Bernardino Mountains	--	--
DISTRICT MAXIMUM			3.5
SOUTH COAST AIR BASIN			3.5

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

[a] The federal 8-hour standard (8-hour average CO > 9 ppm) and state 8-hour standard (8-hour average CO > 9.0 ppm) were not exceeded. The federal and state 1-hour standards (35 ppm and 20 ppm) were not exceeded either.

TABLE 3.2-2 (Continued)
2013 Air Quality Data for SCAQMD

OZONE (O_3)

Source Recep Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hr	Max. Conc. in ppm 8-hr	Fourth High Conc. ppm 8-hr	Health Advisory ≥ 0.15 ppm 1-hr	No. Days Standard Exceeded: Federal: Old > 0.124 ppm 1-hr	No. Days Standard Exceeded: Federal: Current >0.075 ppm 8-hr	No. Days Standard Exceeded: State: Current > 0.09 ppm 1-hr	No. Days Standard Exceeded: State: Current > 0.070 ppm 8-hr
LOS ANGELES COUNTY										
1	Central Los Angeles	365	0.081	0.069	0.060	0	0	0	0	0
2	Northwest Coastal LA County	359	0.088	0.075	0.059	0	0	0	0	1
3	Southwest Coastal LA County	352	0.105	0.081	0.060	0	0	1	1	1
4	South Coastal Los Angeles County 1	267*	0.092	0.070	0.060	0	0	0	0	0
4	South Coastal Los Angeles County 2	--	--	--	--	--	--	--	--	--
4	South Coastal LA County 3	362	0.090	0.069	0.057	0	0	0	0	0
6	West San Fernando Valley	320	0.124	0.092	0.084	0	0	11	7	21
7	East San Fernando Valley	362	0.110	0.083	0.079	0	0	6	4	17
8	West San Gabriel Valley	211*	0.099	0.075	0.070	0	0	0	2	2
9	East San Gabriel Valley 1	361	0.115	0.085	0.080	0	0	6	7	15
9	East San Gabriel Valley 2	340	0.135	0.100	0.088	0	1	24	24	43
10	Pomona/Walnut Valley	355	0.125	0.099	0.085	0	1	15	12	22
11	South San Gabriel Valley	363	0.101	0.072	0.070	0	0	0	2	3
12	South Central Los Angeles County	358	0.090	0.080	0.063	0	0	1	0	1
13	Santa Clarita Valley	365	0.134	0.104	0.094	0	2	40	30	58
ORANGE COUNTY										
16	North Orange County	363	0.104	0.078	0.066	0	0	1	2	2
17	Central Orange County	340	0.084	0.070	0.063	0	0	0	0	0
18	North Coastal Orange County	385	0.095	0.083	0.065	0	0	1	1	2
19	Saddleback Valley	365	0.104	0.082	0.074	0	0	2	2	5
RIVERSIDE COUNTY										
22	Norco/Corona	--	--	--	--	--	--	--	--	--
23	Metropolitan Riverside County 1	357	0.123	0.103	0.094	0	0	26	13	38
23	Metropolitan Riverside County 2	--	--	--	--	--	--	--	--	--
23	Mira Loma	365	0.118	0.096	0.092	0	0	21	11	32
24	Perris Valley	344	0.108	0.090	0.088	0	0	34	17	60
25	Lake Elsinore	362	0.102	0.089	0.081	0	0	12	6	25
26	Temecula	324	0.093	0.078	0.075	0	0	3	0	12
29	Banning Airport	254*	0.115	0.103	0.091	0	0	41	24	66
30	Coachella Valley 1**	365	0.113	0.104	0.090	0	0	46	10	82
30	Coachella Valley 2**	365	0.105	0.087	0.085	0	0	18	2	38
SAN BERNARDINO COUNTY										
32	Northwest San Bernardino Valley	365	0.143	0.111	0.095	0	3	27	25	44
33	Southwest San Bernardino Valley	--	--	--	--	--	--	--	--	--
34	Central San Bernardino Valley 1	363	0.151	0.122	0.100	1	2	42	34	68
34	Central San Bernardino Valley 2	361	0.139	0.112	0.097	0	2	36	22	53
35	East San Bernardino Valley	356	0.133	0.119	0.104	0	3	63	43	93
37	Central San Bernardino Mountains	365	0.120	0.105	0.099	0	0	72	45	101
38	East San Bernardino Mountains	--	--	--	--	--	--	--	--	--
	DISTRICT MAXIMUM		0.151	0.122	0.104	1	3	72	45	101
	SOUTH COAST AIR BASIN		0.151	0.122	0.104	1	5	88	70	119

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

TABLE 3.2-2 (Continued)
2013 Air Quality Data for SCAQMD

NITROGEN DIOXIDE (NO_2) [b)]					
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	1-hour Max. Conc. ppb	1-hour 98th Percentile Conc. ppb	Annual Average AAM Conc. ppb
LOS ANGELES COUNTY					
1	Central Los Angeles	301	90.3	62.6	21.8
2	Northwest Coastal Los Angeles County	291	51.2	48.8	14.5
3	Southwest Coastal Los Angeles County	334	77.8	58.0	11.8
4	South Coastal Los Angeles County 1	234*	66.9	55.7	14.0
4	South Coastal Los Angeles County 2	--	--	--	--
4	South Coastal LA County 3	325	81.3	71.3	21.5
6	West San Fernando Valley	258*	58.2	51.7	14.4
7	East San Fernando Valley	284	72.5	60.0	20.2
8	West San Gabriel Valley	200*	66.7	60.3	19.1
9	East San Gabriel Valley 1	352	76.9	56.7	17.7
9	East San Gabriel Valley 2	349	55.7	50.4	13.0
10	Pomona/Walnut Valley	343	78.8	64.8	22.5
11	South San Gabriel Valley	337	79.4	60.6	20.6
12	South Central Los Angeles County	340	69.8	61.8	17.6
13	Santa Clarita Valley	362	65.4	45.0	14.4
ORANGE COUNTY					
16	North Orange County	269*	85.0	53.3	14.8
17	Central Orange County	301	81.6	58.8	18.0
18	North Coastal Orange County	330	75.7	53.2	11.6
19	Saddleback Valley	--	--	--	--
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metropolitan Riverside County 1	318	59.6	54.8	17.3
23	Metropolitan Riverside County 2	257*	57.6	50.7	15.8
23	Mira Loma	333	53.8	50.7	13.7
24	Perris Valley	--	--	--	--
25	Lake Elsinore	294	46.6	40.0	8.4
26	Temecula	--	--	--	--
29	Banning Airport	308	51.9	45.0	8.5
30	Coachella Valley 1**	359	52.3	38.5	7.5
30	Coachella Valley 2**	--	--	--	--
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	276*	62.1	53.3	17.7
33	Southwest San Bernardino Valley	--	--	--	--
34	Central San Bernardino Valley 1	335	81.7	60.6	20.6
34	Central San Bernardino Valley 2	291	72.2	54.5	17.6
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM			90.3	71.3	22.5
SOUTH COAST AIR BASIN			90.3	71.3	22.5

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin
ppb = parts per billion AAM = Annual Arithmetic Mean

b) The NO2 federal 1-hour standard is 100 ppb and the annual standard is annual arithmetic mean NO_2 > 0.0534 ppm. The state 1-hour and annual standards are 0.18 ppm (180 ppb) and 0.030 ppm (30 ppb).

TABLE 3.2-2 (Continued)
2013 Air Quality Data for SCAQMD

SULFUR DIOXIDE (SO_2) [c]				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Conc. ppb, 1-hour	99th Percentile Conc. ppb, 1-hour
LOS ANGELES COUNTY				
1	Central Los Angeles	312	6.3	5.2
2	Northwest Coastal Los Angeles County	--	--	--
3	Southwest Coastal Los Angeles County	322	10.1	6.5
4	South Coastal Los Angeles County 1	178*	21.8	10.1
4	South Coastal Los Angeles County 2	--	--	--
4	South Coastal LA County 3	349	15.1	11.6
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	342	10.8	4.2
8	West San Gabriel Valley	--	--	--
9	East San Gabriel Valley 1	--	--	--
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	--	--	--
12	South Central Los Angeles County	--	--	--
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	--	--	--
17	Central Orange County	--	--	--
18	North Coastal Orange County	296	4.2	3.3
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	354	8.1	4.6
23	Metropolitan Riverside County 2	--	--	--
23	Mira Loma	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
26	Temecula	--	--	--
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	--	--	--
33	Southwest San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	298	3.8	3.1
34	Central San Bernardino Valley 2	--	--	--
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
DISTRICT MAXIMUM			21.8	11.6
SOUTH COAST AIR BASIN			21.8	11.6

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin
ppb = parts per billion

c) The federal SO2 1-hour standard is 75 ppb (0.075 ppm). The state standards are 1-hour average SO_2 > 0.25 ppm (250 ppb) and 24-hour average SO_2 > 0.04 ppm (40 ppb).

TABLE 3.2-2 (Continued)
2013 Air Quality Data for SCAQMD

SUSPENDED PARTICULATE MATTER PM10 d)						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. µg/m³, 24-hour	No. (%) Samples Exceeding Standard: Federal > 150 µg/m³, 24-hour	No. (%) Samples Exceeding Standard: State > 50 µg/m³, 24-hour	Annual Average AAM Conc. e) µg/m³
LOS ANGELES COUNTY						
1	Central Los Angeles	60	57	0	1(2%)	29.5
2	Northwest Coastal Los Angeles County	--	--	--	--	--
3	Southwest Coastal Los Angeles County	56	38	0	0	20.8
4	South Coastal Los Angeles County 1	43*	37	0	0	23.2
4	South Coastal Los Angeles County 2	56	54	0	1(2%)	27.3
4	South Coastal LA County 3	--	--	--	--	--
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	58	52	0	1(2%)	28.5
8	West San Gabriel Valley	--	--	--	--	--
9	East San Gabriel Valley 1	61	76	0	6(10%)	33.0
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central Los Angeles County	--	--	--	--	--
13	Santa Clarita Valley	60	43	0	0	21.6
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	59	77	0	1(2%)	25.4
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	61	51	0	1(2%)	19.3
RIVERSIDE COUNTY						
22	Norco/Corona	57	58	0	2(4%)	28.3
23	Metropolitan Riverside County 1	119	135	0	10(8%)	33.8
23	Metropolitan Riverside County 2	--	--	--	--	--
23	Mira Loma	59	147	0	14(24%)	41.1
24	Perris Valley	57	70	0	10(18%)	33.6
25	Lake Elsinore	--	--	--	--	--
26	Temecula	--	--	--	--	--
29	Banning Airport	61	64	0	1(2%)	20.6
30	Coachella Valley 1**	60	129	0	3(5%)	22.6
30	Coachella Valley 2**	120	129+	0+	23(19%)	38.1
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	60	115	0	3(5%)	33.2
34	Central San Bernardino Valley 1	61	90	0	19(31%)	40.6
34	Central San Bernardino Valley 2	60	102	0	3(5%)	31.3
35	East San Bernardino Valley	61	72	0	2(3%)	27.1
37	Central San Bernardino Mountains	60	37	0	0	21.4
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM		147+	0+	23	41.1
	SOUTH COAST AIR BASIN		147	0	33	41.1

KEY: µg/m³ = micrograms per cubic meter of air -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

AAM = Annual Arithmetic Mean

\+ = High PM10 data sample (159 µg/m³ on August 23, 2013 at Indio) excluded due to the high wind in accordance with the EPA Exceptional Event Regulation. Also, multiple high PM10FEM data recorded in Coachella Valley and the Basin were excluded.

d) Federal Reference Method (FRM) PM10 samples were collected every six days at all sites except for Stations 4144 and 4157, where samples were collected every three days. PM10 statistics listed above are for the FRM data only. Federal Equivalent Method (FEM) PM10 continuous monitoring instruments were operated at some of the above locations. Max 24-hour average PM10 at sites with FEM monitoring was 153 µg/m³ at Indio (155 µg/m³ is needed to exceed the PM10 standards.

e) Federal annual PM10 standard (AAM > 50 µg/m³) was revoked in 2006. State standard is annual average (AAM) > 20 µg/m³.

TABLE 3.2-2 (Continued)
2013 Air Quality Data for SCAQMD

FINE PARTICULATE MATTER PM2.5 [f]						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. µg/m³, 24-hour	98th Percentile Conc. in µg/m³ 24-hr	No. (%) Samples Exceeding Federal Std > 35 µg/m³, 24-hour	Annual Average AAM Conc. [g] µg/m³
LOS ANGELES COUNTY						
1	Central Los Angeles	344	43.1	29.0	1(0.3%)	11.95
2	Northwest Coastal Los Angeles County	--	--	--	--	--
3	Southwest Coastal Los Angeles County	--	--	--	--	--
4	South Coastal Los Angeles County 1	331	47.2	26.1	2(0.6%)	11.34
4	South Coastal Los Angeles County 2	341	42.9	24.6	1(0.3%)	10.97
4	South Coastal LA County 3	--	--	--	--	--
6	West San Fernando Valley	118	41.8	23.0	1(0.8%)	9.71
7	East San Fernando Valley	346	45.1	30.4	4(1.2%)	12.15
8	West San Gabriel Valley	64*	25.7	20.5	0(0%)	10.13
9	East San Gabriel Valley 1	120	29.6	26.4	0(0%)	10.54
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	114	29.1	28.8	0(0%)	11.56
12	South Central Los Angeles County	113	52.1	24.3	1(0.9%)	11.95
13	Santa Clarita Valley	--	--	--	--	--
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	331	37.8	22.7	1(0.3%)	10.09
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	117	28.0	17.5	0(0%)	8.08
RIVERSIDE COUNTY						
22	Norco/Corona	--	--	--	--	--
23	Metropolitan Riverside County 1	353	60.3	34.6	6(1.7%)	12.50
23	Metropolitan Riverside County 2	117	53.7	29.2	1(0.9%)	11.28
23	Mira Loma	355	56.5	37.5	9(2.5%)	14.12
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	--	--	--	--	--
26	Temecula	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	117	18.5	13.8	0(0%)	6.52
30	Coachella Valley 2**	118	25.8	15.9	0(0%)	8.35
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	110	49.3	26.8	1(0.9%)	11.98
34	Central San Bernardino Valley 1	121	43.6	33.1	1(0.8%)	12.26
34	Central San Bernardino Valley 2	110	55.3	33.4	1(0.9%)	11.41
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	59	35.5	35.1	1(1.7%)	9.67
DISTRICT MAXIMUM			60.3	37.5	9	14.12
SOUTH COAST AIR BASIN			60.4	37.5	13	14.12

KEY: µg/m3 = micrograms per cubic meter of air -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin
AAM = Annual Arithmetic Mean

f) PM2.5 samples were collected every three days at all sites except for station numbers 069, 072, 077, 087,3176, 4144 and 4165, where samples were taken daily, and station number 5818 where samples were taken every six days. PM10 statistics listed above are for the Federal Reference Method (FRM) data only. Federal Equivalent Method (FEM) PM2.5 continuous monitoring instruments were operated at some of the above locations for special purposes with the max 24-hour average concentration recorded of 83.2 µg/m³, (at Mira Loma).

g) USEPA has revised the federal annual PM2.5 standard from annual average (AAM) > 15.0 µg/m³ to 12 µg/m³, effective March 18, 2013. State standard is annual average (AAM) > 12 µg/m³.

TABLE 3.2-2 (Concluded)
2013 Air Quality Data for SCAQMD

		LEAD h)		PM10 SULFATES i)	
Source Receptor Area No.	Location of Air Monitoring Station	Max. Monthly Average Conc. µg/m³	Max. 3-Months Rolling Averages, µg/m³	No. Days of Data	Max. Conc. µg/m³, 24-hour
LOS ANGELES COUNTY					
1	Central Los Angeles	0.013	0.011	60	5.8
2	Northwest Coastal Los Angeles County	--	--	--	--
3	Southwest Coastal Los Angeles County	0.005	0.004	56	5.6
4	South Coastal Los Angeles County 1	0.006	0.006	43*	4.5
4	South Coastal Los Angeles County 2	0.012	0.009	56	4.8
4	South Coastal LA County 3	--	--	--	--
6	West San Fernando Valley	--	--	--	--
7	East San Fernando Valley	--	--	58	5.4
8	West San Gabriel Valley	--	--	--	--
9	East San Gabriel Valley 1	--	--	61	4.8
9	East San Gabriel Valley 2	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--
11	South San Gabriel Valley	0.012	0.011	--	--
12	South Central Los Angeles County	0.014	0.011	--	--
13	Santa Clarita Valley	--	--	60	3.7
ORANGE COUNTY					
16	North Orange County	--	--	--	--
17	Central Orange County	--	--	59	4.7
18	North Coastal Orange County	--	--	--	--
19	Saddleback Valley	--	--	61	4.4
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	57	4.2
23	Metropolitan Riverside County 1	0.010	0.009	119	4.2
23	Metropolitan Riverside County 2	0.007	0.006	--	--
23	Mira Loma	--	--	59	4.2
24	Perris Valley	--	--	57	3.4
25	Lake Elsinore	--	--	--	--
26	Temecula	--	--	--	--
29	Banning Airport	--	--	61	2.9
30	Coachella Valley 1**	--	--	60	3.5
30	Coachella Valley 2**	--	--	120	3.9
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	0.008	0.006	--	--
33	Southwest San Bernardino Valley	--	--	60	4.8
34	Central San Bernardino Valley 1	--	--	61	4.1
34	Central San Bernardino Valley 2	0.010	0.010	60	4.6
35	East San Bernardino Valley	--	--	61	3.6
37	Central San Bernardino Mountains	--	--	60	3.6
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM		0.013++	0.011++		5.8
SOUTH COAST AIR BASIN		0.013++	0.011++		5.8

KEY: µg/m³ = micrograms per cubic meter of air -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

++ = Higher lead concentrations were recorded at source-oriented monitoring sites immediately downwind of stationary lead sources. Maximum monthly and 3-month rolling averages recorded were 0.14 µg/m³ and 0.10 µg/m³, respectively.

h) Federal lead standard is 3-month rolling average > 0.15 µg/m³; and state standard is monthly average ≥ 1.5 µg/m³. Lead statistics listed above are for population-oriented sites only. Lead standards were not exceeded.

i) State sulfate standard is 24-hour ≥ 25 µg/m³. There is no federal standard for sulfate.

Carbon Monoxide

Carbon monoxide (CO) is a colorless, odorless, relatively inert gas. It is a trace constituent in the unpolluted troposphere, and is produced by both natural processes and human activities. In remote areas far from human habitation, CO occurs in the atmosphere at an average background concentration of 0.04 parts per million (ppm), primarily as a result of natural processes such as forest fires and the oxidation of methane. Global atmospheric mixing of CO from urban and industrial sources creates higher background concentrations (up to 0.20 ppm) near urban areas. The major source of CO in urban areas is incomplete combustion of carbon-containing fuels, mainly gasoline. Approximately 98 percent of the CO emitted into the Basin's atmosphere is from mobile sources. Consequently, CO concentrations are generally highest in the vicinity of major concentrations of vehicular traffic.

CO is a primary pollutant, meaning that it is directly emitted into the air, not formed in the atmosphere by chemical reaction of precursors, as is the case with ozone and other secondary pollutants. Ambient concentrations of CO in the Basin exhibit large spatial and temporal variations due to variations in the rate at which CO is emitted and in the meteorological conditions that govern transport and dilution. Unlike ozone, CO tends to reach high concentrations in the fall and winter months. The highest concentrations frequently occur on weekdays at times consistent with rush hour traffic and late night during the coolest, most stable portion of the day.

Individuals with a deficient blood supply to the heart are the most susceptible to the adverse effects of CO exposure. The effects observed include earlier onset of chest pain with exercise, and electrocardiograph changes indicative of worsening oxygen supply to the heart.

Inhaled CO has no direct toxic effect on the lungs, but exerts its effect on tissues by interfering with oxygen transport by competing with oxygen to combine with hemoglobin present in the blood to form carboxyhemoglobin (COHb). Hence, conditions with an increased demand for oxygen supply can be adversely affected by exposure to CO. Individuals most at risk include patients with diseases involving heart and blood vessels, fetuses (unborn babies), and patients with chronic hypoxemia (oxygen deficiency) as seen in high altitudes.

Reductions in birth weight and impaired neurobehavioral development have been observed in animals chronically exposed to CO resulting in COHb levels similar to those observed in smokers. Recent studies have found increased risks for adverse birth outcomes with exposure to elevated CO levels. These include pre-term births and heart abnormalities.

CO concentrations were measured at 26 locations in the Basin and neighboring Salton Sea Air Basin (SSAB) areas in 2013. Carbon monoxide concentrations did not exceed any of the federal or state standards in 2013. The highest eight-hour average carbon monoxide concentration recorded (3.5 ppm in the South Central Los Angeles County area) was 39 percent of the federal eight-hour carbon monoxide standard of 9.0 ppm. The state eight-hour standard is also 9.0 ppm.

The 2003 AQMP revisions to the SCAQMD's CO Plan served two purposes: 1) it replaced the 1997 attainment demonstration that lapsed at the end of 2000; and, 2) it provided the basis for a CO maintenance plan in the future. In 2004, the SCAQMD formally requested the USEPA to re-designate the Basin from non-attainment to attainment with the CO National Ambient Air Quality Standards. On February 24, 2007, USEPA published in the FR its proposed decision to re-designate the Basin from non-attainment to attainment for CO. The comment period on the re-designation proposal closed on March 16, 2007 with no comments received by the USEPA. On May 11, 2007, USEPA published in the FR its final decision to approve the SCAQMD's request for re-designation from non-attainment to attainment for CO, effective June 11, 2007.

Ozone

Ozone (O3), a colorless gas with a sharp odor, is a highly reactive form of oxygen. High ozone concentrations exist naturally in the stratosphere. Some mixing of stratospheric ozone downward through the troposphere to the earth's surface does occur; however, the extent of ozone transport is limited. At the earth's surface in sites remote from urban areas ozone concentrations are normally very low (e.g., from 0.02 ppm to 0.045 ppm), however recent studies indicate that the 'background' value of ozone may be rising due to the increased influence of pollution from global pollution produced outside of the SCAQMD[3, 4].

While ozone is beneficial in the stratosphere because it filters out skin-cancer-causing ultraviolet radiation, it is a highly reactive oxidant. It is this reactivity which accounts for its damaging effects on materials, plants, and human health at the earth's surface.

The propensity of ozone for reacting with organic materials causes it to be damaging to living cells and ambient ozone concentrations in the Basin are frequently sufficient to cause health effects. Ozone enters the human body primarily through the respiratory tract and causes respiratory irritation and discomfort, makes breathing more difficult during exercise, and reduces the respiratory system's ability to remove inhaled particles and fight infection.

Individuals exercising outdoors, children and people with preexisting lung disease, such as asthma and chronic pulmonary lung disease, are considered to be the most susceptible subgroups for ozone effects. Short-term exposures (lasting for a few hours) to ozone at levels typically observed in southern California can result in breathing pattern changes, reduction of breathing capacity, increased susceptibility to infections, inflammation of the lung tissue, and some immunological changes. In recent years, a correlation between elevated ambient ozone levels and increases in daily hospital admission rates, as well as mortality, has also been reported. An increased risk for asthma has been found in children who participate in multiple sports and live in high ozone communities. Elevated ozone levels are also associated with increased school absences.

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[3] Fiore et al, "Background Ozone Over the United States in Summer: Origin, Trend, and Contribution to Pollution Episodes," Journal of Geophysical Research - Atmospheres, Vol. 107 - D15, 2002, pp. ACH 11-1–ACH 11-25. http://onlinelibrary.wiley.com/doi/10.1029/2001JD000982/abstract

[4] R. Vingarzan, "A Review of Surface Ozone Background Levels and Trends," Atmospheric Environment, Volume 38,2004, pp. 3431–3442. http://www.sciencedirect.com/science/article/pii/S1352231004002808

Ozone exposure under exercising conditions is known to increase the severity of the abovementioned observed responses. Animal studies suggest that exposures to a combination of pollutants which include ozone may be more toxic than exposure to ozone alone. Although lung volume and resistance changes observed after a single exposure diminish with repeated exposures, biochemical and cellular changes appear to persist, which can lead to subsequent lung structural changes.

In 2013, the SCAQMD regularly monitored ozone concentrations at 31 locations in the Basin and SSAB. Maximum ozone concentrations for all areas monitored were below the stage 1 episode level (0.20 ppm). Maximum ozone concentrations in the SSAB areas monitored by the SCAQMD were lower than the maximum values found in the Basin.

In 2013, the maximum ozone concentrations in the Basin continued to exceed federal standards by wide margins. The maximum one-hour ozone concentration was 0.151 ppm and the maximum eight-hour ozone concentration was 0.122 ppm; both were recorded in the Central San Bernardino Valley 1 area. The federal one-hour ozone standard was revoked and replaced by the eight-hour average ozone standard effective June 15, 2005. Effective May 27, 2008, the USEPA revised the federal eight-hour ozone standard from 0.84 ppm to 0.075 ppm. The maximum eight-hour concentration was 163 percent of the current federal standard. The maximum one-hour concentration was 168 percent of the one-hour state ozone standard of 0.09 ppm. The maximum eight-hour concentration was 174 percent of the eight-hour state ozone standard of 0.070 ppm.

Nitrogen Dioxide

Nitrogen Dioxide (NO2) is a reddish-brown gas with a bleach-like odor. Nitric oxide (NO) is a colorless gas, formed from the nitrogen (N2) and oxygen (O2) in air under conditions of high temperature and pressure which are generally present during combustion of fuels; NO reacts rapidly with the oxygen in air to form NO2. NO2 is responsible for the brownish tinge of polluted air. The two gases, NO and NO2, are referred to collectively as NOx. In the presence of sunlight, NO2 reacts to form nitric oxide and an oxygen atom. The oxygen atom can react further to form ozone, via a complex series of chemical reactions involving hydrocarbons. Nitrogen dioxide may also react to form nitric acid (HNO3) which reacts further to form nitrates, components of PM2.5 and PM10.

Population-based studies suggest that an increase in acute respiratory illness, including infections and respiratory symptoms in children (not infants), is associated with long-term exposures to NO2 at levels found in homes with gas stoves, which are higher than ambient levels found in southern California. Increase in resistance to air flow and airway contraction is observed after short-term exposure to NO2 in healthy subjects. Larger decreases in lung functions are observed in individuals with asthma and/or chronic obstructive pulmonary disease (e.g., chronic bronchitis, emphysema) than in healthy individuals, indicating a greater susceptibility of these sub-groups. More recent studies have found associations between NO2 exposures and cardiopulmonary mortality, decreased lung function, respiratory symptoms and emergency room asthma visits.

In animals, exposure to levels of NO_2 considerably higher than ambient concentrations results in increased susceptibility to infections, possibly due to the observed changes in cells involved in maintaining immune functions. The severity of lung tissue damage associated with high levels of ozone exposure increases when animals are exposed to a combination of ozone and NO_2.

In 2013, NO_2 concentrations were monitored at 26 locations. No area of the Basin or SSAB exceeded the federal or state standards for nitrogen dioxide. The Basin has not exceeded the federal standard for nitrogen dioxide (0.0534 ppm) since 1991, when the Los Angeles County portion of the Basin recorded the last exceedance of the standard in any county within the U.S.

In 2013, the maximum annual average concentration was 22.5 parts per billion (ppb) recorded in the Pomona/Walnut Valley area. Effective March 20, 2008, CARB revised the nitrogen dioxide one-hour standard from 0.25 ppm (250 ppb) to 0.18 ppm (180 ppb) and established a new annual standard of 0.030 ppm (30 ppb). In addition, USEPA has established a new federal one-hour NO_2 standard of 100 ppb (98th percentile concentration), effective April 7, 2010. The highest one-hour maximum concentration recorded in 2013 (90.3 ppb in Central Los Angeles County area) was 50 percent of the state one-hour standard. The highest one-hour 98th percentile concentration, recorded in 2013 (71.3 ppb in the South Coastal Los Angeles County area near the ports of Los Angeles and Long Beach), was 40 percent of the state one-hour standard and 71 percent of the federal one-hour standard. NO_x emission reductions continue to be necessary because it is a precursor to both ozone and PM ($PM_{2.5}$ and PM_{10}) concentrations.

<u>Sulfur Dioxide</u>

Sulfur dioxide (SO_2) is a colorless gas with a sharp odor. It reacts in the air to form sulfuric acid (H_2SO_4), which contributes to acid precipitation, and sulfates, which are components of PM_{10} and $PM_{2.5}$. Most of the SO_2 emitted into the atmosphere is produced by burning sulfur-containing fuels.

Exposure of a few minutes to low levels of SO_2 can result in airway constriction in some asthmatics. All asthmatics are sensitive to the effects of SO_2. In asthmatics, increase in resistance to air flow, as well as reduction in breathing capacity leading to severe breathing difficulties, is observed after acute higher exposure to SO_2. In contrast, healthy individuals do not exhibit similar acute responses even after exposure to higher concentrations of SO_2.

Animal studies suggest that despite SO_2 being a respiratory irritant, it does not cause substantial lung injury at ambient concentrations. However, very high levels of exposure can cause lung edema (fluid accumulation), lung tissue damage, and sloughing off of cells lining the respiratory tract.

Some population-based studies indicate that the mortality and morbidity effects associated with fine particles show a similar association with ambient SO_2 levels. In these studies, efforts to separate the effects of SO_2 from those of fine particles have not been successful.

It is not clear whether the two pollutants act synergistically or one pollutant alone is the predominant factor.

No exceedances of federal or state standards for SO2 occurred in 2013 at any of the eight monitoring locations. The maximum one-hour SO2 concentration was 21.8 ppb, as recorded in the South Coastal Los Angeles County 1 area. The USEPA revised the federal sulfur dioxide standard by establishing a new one-hour standard of 0.075 ppm (75 ppb) and revoking the existing annual arithmetic mean (0.03 ppm) and the 24-hour average (0.14 ppm), effective August 2, 2010. The state standards are 0.25 ppm (250 ppb) for the one-hour average and 0.04 ppm (40 ppb) for the 24-hour average. Though SO2 concentrations remain well below the standards, SO2 is a precursor to sulfate, which is a component of fine particulate matter, PM10, and PM2.5. Because historical measurements have consistently showed concentrations to be well below standards, monitoring has been limited to locations within the District that may have higher concentrations and higher potential exposures to the pollutant.

Particulate Matter (PM10 and PM2.5)

Of great concern to public health are the particles small enough to be inhaled into the deepest parts of the lung. Respirable particles (particulate matter less than about 10 micrometers in diameter) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM10 and PM2.5.

A consistent correlation between elevated ambient fine particulate matter (PM10 and PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks and the number of hospital admissions has been observed in different parts of the U.S. and various areas around the world. Studies have reported an association between long-term exposure to air pollution dominated by fine particles (PM2.5) and increased mortality, reduction in life-span, and an increased mortality from lung cancer.

Daily fluctuations in fine particulate matter concentration levels have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter. In addition to children, the elderly, and people with pre-existing respiratory and/or cardiovascular disease appear to be more susceptible to the effects of PM10 and PM2.5.

The SCAQMD monitored PM10 concentrations at 21 locations in 2013. The federal 24-hour PM10 standard (150 $\mu g/m^3$) was not exceeded at any of the locations monitored in 2013. The federal annual PM10 standard has been revoked, effective 2006. A maximum 24-hour PM10 concentration of 147 $\mu g/m^3$ was recorded in the Mira Loma area and was 98 percent of the federal standard and 294 percent of the much more stringent state 24-hour PM10 standard (50 $\mu g/m^3$). The state 24-hour PM10 standard was exceeded at 17 of the 21 monitoring stations. A maximum annual average PM10 concentration of 41.1 $\mu g/m^3$ was recorded in Mira Loma. The maximum annual average PM10 concentration in Mira Loma was 206 percent of the state standard of 20 µg/m^3. The USEPA published approval of SCAQMD's PM10 request for redesignation for attainment on June 26, 2013, with an implementation date of July 26, 2013.

In 2013, PM2.5 concentrations were monitored at 20 locations throughout the district. USEPA revised the federal 24-hour PM2.5 standard from 65 µg/m^3 to 35 µg/m^3, effective December 17, 2006, and retained the form of the standard using the 98th percentile each year, averaged over three years. In 2013, the 98th percentile PM2.5 concentrations in the Basin exceeded the current federal 24-hour PM2.5 standard in two of the 20 locations. A 98th percentile 24-hour PM2.5 concentration of 37.5 µg/m^3 was recorded in the Metropolitan Riverside County 1 area, which represents 107 percent of the federal standard of 35 µg/m^3. Further, in July 2015, SCAQMD staff submitted a letter to EPA requesting a change in its attainment status to 'Serious' non-attainment due to high 24-hour concentrations of PM2.5 persisting through 2015. A maximum annual average PM2.5 concentration of 14.12 µg/m^3 was recorded in Mira Loma, which represents 118 percent of both the federal and state standard of 12 µg/m^3.

Similar to PM10 concentrations, PM2.5 concentrations were higher in the inland valley areas of San Bernardino and Metropolitan Riverside counties. However, PM2.5 concentrations were also high in Central Los Angeles County and the East San Gabriel Valley. The high PM2.5 concentrations in Los Angeles County are mainly due to the secondary formation of smaller particulates resulting from mobile and stationary source activities. In contrast to PM10, PM2.5 concentrations were low in the Coachella Valley area of SSAB. PM10 concentrations are normally higher in the desert areas due to windblown and fugitive dust emissions.

<u>Lead</u>

Under the federal Clean Air Act, lead is classified as a "criteria pollutant." Lead has observed adverse health effects at ambient concentrations. Lead is also deemed a carcinogenic toxic air contaminant (TAC) by the Office of Environmental Health Hazard Assessment (OEHHA). The USEPA has thoroughly reviewed the lead exposure and health effects research, and has prepared substantial documentation in the form of a Criteria Document to support the selection of the 2008 NAAQS for lead. The Criteria Document used for the development of the 2008 NAAQS for lead states that studies and evidence strongly substantiate that blood lead levels in a range of 5-10 µg/dL, or possibly lower, could likely result in neurocognitive effects in children. The report further states that "there is no level of lead exposure that can yet be identified with confidence, as clearly not being associated with some risk of deleterious health effects[5]."

Fetuses, infants, and children are more sensitive than others to the adverse effects of lead exposure. Exposure to low levels of lead can adversely affect the development and function of the central nervous system, leading to learning disorders, distractibility, inability to follow simple commands, and lower intelligence quotient. In adults, increased lead levels are

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5 Environmental Protection Agency, Office of Research and Development, "Air Quality Criteria Document for Lead, Volumes I-II," October 2006.

associated with increased blood pressure. Chronic health effects include nervous and reproductive system disorders, neurological and respiratory damage, cognitive and behavioral changes, and hypertension. Exposure to lead can also potentially increase the risk of contracting cancer or result in other adverse health effects. Lead has been classified as a probable human carcinogen by the International Agency for Research on Cancer, based mainly on sufficient animal evidence, and as reasonably anticipated to be a human carcinogen by the U.S. National Toxicology Program. Young children are especially susceptible to the effects of environmental lead because their bodies accumulate lead more readily than do those of adults, and because they are more vulnerable to certain biological effects of lead including learning disabilities, behavioral problems, and deficits in IQ.

Lead poisoning can cause anemia, lethargy, seizures, and death. Lead can be stored in the bone from early-age environmental exposure, and elevated blood lead levels can occur due to breakdown of bone tissue during pregnancy, hyperthyroidism (increased secretion of hormones from the thyroid gland), and osteoporosis (breakdown of bone tissue). Fetuses and breast-fed babies can be exposed to higher levels of lead because of previous environmental lead exposure of their mothers.

Lead in the atmosphere is present as a mixture of a number of lead compounds. Leaded fuels and lead smelters have traditionally been the main sources of lead emitted into the air. Due to the phasing out of leaded fuels, there was a dramatic reduction in atmospheric lead in the Basin over the past three decades.

As a result, the federal and current state standards for lead were not exceeded in any area of the district in 2013. There have been no violations of these standards at the SCAQMD's regular air monitoring stations since 1982, as a result of removal of lead from fuels.

On November 12, 2008, USEPA published new NAAQS for lead, which became effective January 12, 2010. The existing national lead standard, 1.5 $\mu g/m^3$, was reduced to 0.15 $\mu g/m^3$, averaged over a rolling three-month period.

The maximum 3-month rolling average lead concentration (0.011 $\mu g/m^3$ was recorded at monitoring stations in Central Los Angeles, South San Gabriel Valley, and South Central LA County areas) was seven percent of the federal 3-month rolling lead standard (0.15 $\mu g/m^3$). The maximum monthly average lead concentration (0.014 $\mu g/m^3$ in South Central Los Angeles County area), measured at special monitoring sites immediately adjacent to stationary sources of lead was 0.9 percent of the state monthly average lead standard (1.5 $\mu g/m^3$). No lead data were obtained at SSAB and Orange County stations in 2013. Because historical lead data showed concentrations in SSAB and Orange County areas to be well below the standard, measurements have been discontinued at these locations.

In 2010, a portion of Los Angeles County was designated as not attaining the NAAQS of 0.15 $\mu g/m^3$ for lead based on monitored air quality data from 2007 to 2009 that indicated a violation of the NAAQS near and due to one of two large lead-acid battery recycling facilities in the District. However, the new federal standard was not exceeded at any source/receptor location the following year (in 2011).

Nevertheless, based on the monitored emissions from the two battery recycling facilities, USEPA designated the Los Angeles County portion of the Basin as non-attainment for the new lead standard, effective December 31, 2010. In response to the new federal lead standard, the SCAQMD adopted Rule 1420.1 – Emissions Standard for Lead from Large Lead-Acid Battery Recycling Facilities, in November 2010, to ensure that lead emissions do not exceed the new federal standard.

In response to the nonattainment designation, the State submitted the *Final 2012 Lead State Implementation Plan – Los Angeles County* (2012 Lead SIP) to the USEPA on June 20, 2012. The plan outlines steps that will bring the area into attainment with the federal lead standard before December 31, 2015. As of February 11, 2014, the USEPA announced in the Federal Register (FR) final approval of the lead air quality plan, to be effective 30 days after publication (e.g., March 12, 2014).

In 2013, higher lead concentrations continued to be recorded at source-oriented monitoring sites immediately downwind of stationary lead sources. The maximum monthly and 3-month rolling averages recorded in 2013 were 0.14 $\mu g/m^3$ and 0.10 $\mu g/m^3$, respectively.

In May 2014, the USEPA released its "Policy Assessment for the Review of the Lead National Ambient Air Quality Standards," reaffirming the primary (health-based) and secondary (welfare-based) staff conclusions regarding whether to retain the current standards. In January 2015, the USEPA announced that the ambient lead concentration standard of 0.15 $\mu g/m^3$ averaged over a rolling 3-month period would remain unchanged. The 90-day comment period for this proposal ended on April 6, 2015 and requires further action by the USEPA.

To continue to pursue reducing lead emissions from large lead-acid battery recycling facilities, in March 2015, Rule 1420.1 was amended to further lower the ambient lead concentration limit to 0.120 $\mu g/m^3$ effective January 1, 2016 and 0.100 $\mu g/m^3$ effective January 1, 2017 and the point source lead emission rate to 0.023 pounds per hour, as well as adding additional housekeeping and maintenance requirements.

On April 7, 2015, the larger of the two lead-acid battery recycling facilities withdrew its California Department of Toxic Substance Control (DTSC) permit application and provided notification of its intent to permanently close.

While Rule 1420.1 will be effective in reducing emissions from the large lead-acid battery recycling industry, lead emissions from the broader industry source category of metal melting is still a concern because the metal melting industry is the most significant stationary source of reported lead emissions. While existing federal and state regulations currently control lead emissions from the metal melting industry, additional requirements similar to those that have effectively reduced emissions from large lead-acid battery recyclers are also necessary to adequately protect public health by minimizing public exposure to lead emissions and preventing exceedances of the lead NAAQS in the Basin. As a result, the SCAQMD is proposing to adopt Rule 1420.2 – Emission Standards for Lead from Metal Melting Facilities which is scheduled to be considered by the SCAQMD Governing Board at its September 4, 2015 public hearing.

Sulfates

Sulfates (SOx) are chemical compounds which contain the sulfate ion and are part of the mixture of solid materials which make up PM10. Most of the sulfates in the atmosphere are produced by oxidation of SO2. Oxidation of sulfur dioxide yields sulfur trioxide (SO3) which reacts with water to form sulfuric acid, which contributes to acid deposition. The reaction of sulfuric acid with basic substances such as ammonia yields sulfates, a component of PM10 and PM2.5.

Most of the health effects associated with fine particles and SO2 at ambient levels are also associated with SOx. Thus, both mortality and morbidity effects have been observed with an increase in ambient SOx concentrations. However, efforts to separate the effects of SOx from the effects of other pollutants have generally not been successful.

Clinical studies of asthmatics exposed to sulfuric acid suggest that adolescent asthmatics are possibly a subgroup susceptible to acid aerosol exposure. Animal studies suggest that acidic particles such as sulfuric acid aerosol and ammonium bisulfate are more toxic than non-acidic particles like ammonium sulfate. Whether the effects are attributable to acidity or to particles remains unresolved.

In 2013, the state 24-hour sulfate standard (25 $\mu g/m^3$) was not exceeded in any of the monitoring locations in the district. There is no federal sulfate standard.

Hydrogen Sulfide

Hydrogen Sulfide (H2S) is a colorless gas with the characteristic foul odor of rotten eggs. H2S is heavier than air, very poisonous, corrosive, flammable, and explosive. H2S is naturally occurring in crude oil and natural gas, but H2S can also be created from the bacterial breakdown of organic matter in the absence of oxygen (e.g., in swamps and sewers). For example, on September 9, 2012, a thunderstorm over the Salton Sea caused odors to be released across the Coachella Valley. The SCAQMD received over 235 complaints of sulfur and rotten egg type odors in response to this natural event. Air samples were taken at several locations around the Salton Sea area to confirm source of odors and results of sampling showed total sulfur gas concentration of 149 ppb. The State air quality standard for H2S is 30 ppb, averaged over one-hour, and the odor threshold for H2S is approximately eight ppb. In response to potential for increasing odor complaints in the future, in October 2013, the SCAQMD installed two H2S monitors in the Coachella Valley to monitor the presence of H2S during odor events at the Salton Sea. The monitors are located at Saul Martinez Elementary School in Mecca and on the Torres Martinez Desert Cahuilla Indian Tribal land near the north end of the Salton Sea.

Vinyl Chloride

Vinyl chloride is a colorless, flammable gas at ambient temperature and pressure. It is also highly toxic and is classified as a carcinogen by the state Office of Environmental Health Hazard Assessment (OEHHA), in addition to the designations by the American Conference of Governmental Industrial Hygienists (confirmed carcinogen in humans) and by the International Agency for Research on Cancer (known to be a human carcinogen). At room temperature, vinyl chloride is a gas with a sickly sweet odor that is easily condensed. However, it is stored as a liquid. Due to the hazardous nature of vinyl chloride to human health there are no end products that use vinyl chloride in its monomer form. Vinyl chloride is a chemical intermediate, not a final product. It is an important industrial chemical chiefly used to produce the polymer polyvinyl chloride (PVC). The process involves vinyl chloride liquid fed to polymerization reactors where it is converted from a monomer to a polymer PVC. The final product of the polymerization process is PVC in either a flake or pellet form. Billions of pounds of PVC are sold on the global market each year. From its flake or pellet form, PVC is sold to companies that heat and mold the PVC into end products such as PVC pipe and bottles.

In the past, vinyl chloride emissions have been associated primarily with sources such as landfills. Risks from exposure to vinyl chloride are considered to be a localized impacts rather than regional impacts. Because landfills in the district are subject to SCAQMD 1150.1 – Control of Gaseous Emissions from Municipal Solid Waste Landfills, which contains stringent requirements for landfill gas collection and control, potential vinyl chloride emissions are below the level of detection. Therefore, the SCAQMD does not monitor for vinyl chloride at its monitoring stations.

Volatile Organic Compounds

It should be noted that there are no state or national ambient air quality standards for volatile organic compounds (VOCs) because they are not classified as criteria pollutants. VOCs are regulated, however, because limiting VOC emissions reduces the rate of photochemical reactions that contribute to the formation of O3, which is a criteria pollutant. VOCs are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

Visibility

In 2005, annual average visibility at Rubidoux (Riverside), the worst case, was just over 10 miles. With the exception of Lake County, which is designated in attainment, all of the air districts in California are currently designated as unclassified with respect to the CAAQS for visibility reducing particles.

In Class-I wilderness areas, which typically have visual range measured in tens of miles, the deciview metric is used to estimate an individual's perception of visibility. The deciview index works inversely to visual range which is measured in miles or kilometers whereby a lower deciview is optimal. In the South Coast Air Basin, the Class-I areas are typically restricted to higher elevations (greater than 6,000 feet above sea level) or far downwind of the metropolitan emission source areas. Visibility in these areas is typically unrestricted due to regional haze despite being in close proximity to the urban setting. The 2005 baseline deciview mapping of the Basin is presented in Figure 3.2-1. All of the Class-I wilderness areas reside in areas having average deciview values less than 20 with many portions of those areas having average deciview values less than 10. By contrast, Rubidoux, in the Basin has a deciview value exceeding 30.

Federal Regional Haze Rule: The federal Regional Haze Rule, established by the USEPA pursuant to CAA §169A establishes the national goal to prevent future and remedy existing impairment of visibility in federal Class I areas (such as federal wilderness areas and national parks). USEPA's visibility regulations (40 CFR Parts 51.300 - 51.309), require states to develop measures necessary to make reasonable progress towards remedying visibility impairment in these federal Class I areas. CAA §169A and USEPA's visibility regulations also require Best Available Retrofit Technology (BART) for certain large stationary sources that were put in place between 1962 and 1977. (See Regional Haze Regulations and Guidelines for BART Determinations, 70 FR 39104, July 6, 2005).

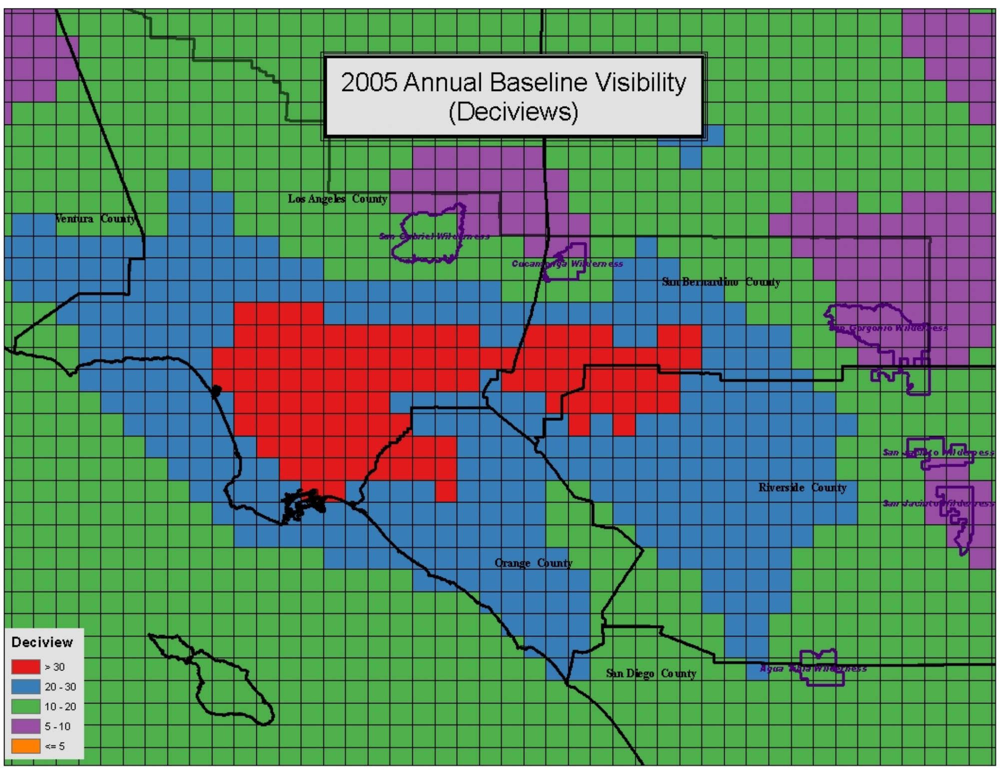

FIGURE 3.2-1
2005 Annual Baseline Visibility

California Air Resources Board: Since deterioration of visibility is one of the most obvious manifestations of air pollution and plays a major role in the public's perception of air quality, the state of California has adopted a standard for visibility or visual range.

Until 1989, the standard was based on visibility estimates made by human observers. The standard was changed to require measurement of visual range using instruments that measure light scattering and absorption by suspended particles.

The visibility standard is based on the distance that atmospheric conditions allow a person to see at a given time and location. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter. Visibility degradation occurs when visibility reducing particles are produced in sufficient amounts such that the extinction coefficient is greater than 0.23 inverse kilometers (to reduce the visual range to less than 10 miles) at relative humidity less than 70 percent, 8-hour average (from 10:00 a.m. to 6:00 p.m.) according to the state standard. Future-year visibility in the Basin is projected empirically using the results derived from a regression analysis of visibility with air quality measurements. The regression data set consisted of aerosol composition data collected during a special monitoring program conducted concurrently with visibility data collection (prevailing visibility observations from airports and visibility measurements from district monitoring stations). A full description of the visibility analysis is given in Appendix V of the 2012 AQMP.

With future year reductions of PM2.5 from implementation of all proposed emission controls for 2015, the annual average visibility would improve from 10 miles (calculated for 2008) to over 20 miles at Rubidoux, for example. Visual range in 2021 at all other Basin sites is expected to equal or exceed the Rubidoux visual range. Visual range is expected to double from the 2008 baseline due to reductions of secondary PM2.5, directly emitted PM2.5 (including diesel soot) and lower NO2 concentrations as a result of 2007 AQMP controls.

To meet Federal Regional Haze Rule requirements, CARB adopted the California Regional Haze Plan on January 22, 2009, addressing California's visibility goals through 2018. As shown in Table 3.2-1, California's statewide standard (applicable outside of the Lake Tahoe area) for Visibility Reducing Particles is an extinction coefficient of 0.23 per kilometer over an 8-hour averaging period. This translates to visibility of ten miles or more due to particles when relative humidity is less than 70 percent.

3.2.2 Non-Criteria Pollutants

Although the SCAQMD's primary mandate is attaining the State and National Ambient Air Quality Standards for criteria pollutants within the district, SCAQMD also has a general responsibility pursuant to HSC §41700 to control emissions of air contaminants and prevent endangerment to public health. Additionally, state law requires the SCAQMD to implement airborne toxic control measures (ATCM) adopted by CARB, and to implement the Air Toxics "Hot Spots" Act. As a result, the SCAQMD has regulated pollutants other than criteria pollutants such as TACs, greenhouse gases and stratospheric ozone depleting compounds. The SCAQMD has developed a number of rules to control non-criteria pollutants from both new and existing sources. These rules originated through state directives, CAA requirements, or the SCAQMD rulemaking process.

In addition to promulgating non-criteria pollutant rules, the SCAQMD has been evaluating AQMP control measures as well as existing rules to determine whether or not they would affect, either positively or negatively, emissions of non-criteria pollutants. For example, rules in which VOC components of coating materials are replaced by a non-photochemically reactive chlorinated substance would reduce the impacts resulting from ozone formation, but could increase emissions of toxic compounds or other substances that may have adverse impacts on human health.

The following subsections summarize the existing setting for the two major categories of non-criteria pollutants: compounds that contribute to TACs, global climate change, and stratospheric ozone depletion.

3.2.2.1 Air Quality – Toxic Air Contaminants

Federal

Under the CAA §112, the USEPA is required to regulate sources that emit one or more of the 187 federally listed hazardous air pollutants (HAPs). HAPs are air toxic pollutants identified in the CAA, which are known or suspected of causing cancer or other serious health effects. The federal HAPs are listed on the USEPA website at http://www.epa.gov/ttn/atw/orig189.html. In order to implement the CAA, approximately 100 National Emission Standards for Hazardous Air Pollutants (NESHAPs) have been promulgated by USEPA for major sources (sources emitting greater than 10 tons per year of a single HAP or greater than 25 tons per year of multiple HAPs). The SCAQMD can either directly implement NESHAPs or adopt rules that contain requirements at least as stringent as the NESHAP requirements. However, since NESHAPs often apply to sources in the district that are already controlled by state-mandated air toxics control measures or by local district rules, many of the sources that would have been subject to federal requirements already comply.

In addition to the major source NESHAPs, USEPA has also controlled HAPs from urban areas by developing Area Source NESHAPs under their Urban Air Toxics Strategy. USEPA defines an area source as a source that emits less than 10 tons annually of any single hazardous air pollutant or less than 25 tons annually of a combination of hazardous air pollutants. The CAA requires the USEPA to identify a list of at least 30 air toxics that pose the greatest potential health threat in urban areas. USEPA is further required to identify and establish a list of area source categories that represent 90 percent of the emissions of the 30 urban air toxics associated with area sources, for which Area Source NESHAPs are to be developed under the CAA. USEPA has identified a total of 70 area source categories with regulations promulgated for more than 30 categories so far.

The federal toxics program recognizes diesel engine exhaust as a health hazard, however, diesel particulate matter itself is not one of their listed toxic air contaminants (TACs). Rather, each toxic compound in the speciated list of compounds in exhaust is considered separately. Although there are no specific NESHAP regulations for diesel PM, diesel particulate emission reductions are realized through federal regulations including diesel fuel standards and emission standards for stationary, marine, and locomotive engines; and idling controls for locomotives.

State

The California air toxics program was based on the CAA and the original federal list of hazardous air pollutants. The state program was established in 1983 under the Toxic Air Contaminant (TAC) Identification and Control Act, Assembly Bill (AB) 1807, Tanner. Under the state program, TACs are identified through a two-step process of risk identification and risk management. This two-step process was designed to protect residents from the health effects of toxic substances in the air.

Control of TACs under the TAC Identification and Control Program: California's TAC identification and control program, adopted in 1983 as AB 1807, is a two-step program in which substances are identified as TACs, and air toxic control measures (ATCMs) are adopted to control emissions from specific sources. CARB has adopted a regulation designating all 187 federal HAPs as TACs.

ATCMs are developed by CARB and implemented by the SCAQMD and other air districts through direct implementation or the adoption of regulations of equal or greater stringency. Generally, the ATCMs reduce emissions to achieve exposure levels below a determined health threshold. If no such threshold levels are determined, emissions are reduced to the lowest level achievable through the best available control technology unless it is determined that an alternative level of emission reduction is adequate to protect public health.

Under California law, a federal NESHAP automatically becomes a state ATCM, unless CARB has already adopted an ATCM for the source category. Once a NESHAP becomes an ATCM, CARB and each air pollution control or air quality management district have certain responsibilities related to adoption or implementation and enforcement of the NESHAP/ATCM.

Control of TACs under the Air Toxics "Hot Spots" Act: The Air Toxics Hot Spots Information and Assessment Act of 1987 (AB 2588) establishes a state-wide program to inventory and assess the risks from facilities that emit TACs and to notify the public about significant health risks associated with the emissions. Facilities are phased into the AB 2588 program based on their emissions of criteria pollutants or their occurrence on lists of toxic emitters compiled by the SCAQMD. Phase I consists of facilities that emit over 25 tons per year of any criteria pollutant and facilities present on the SCAQMD's toxics list. Phase I facilities entered the program by reporting their air TAC emissions for calendar year 1989. Phase II consists of facilities that emit between 10 and 25 tons per year of any criteria pollutant, and submitted air toxic inventory reports for calendar year 1990 emissions. Phase III consists of certain designated types of facilities which emit less than 10 tons per year of any criteria pollutant, and submitted inventory reports for calendar year 1991 emissions. Inventory reports are required to be updated every four years under the state law.

Air Toxics Control Measures: As part of its risk management efforts, CARB has passed state ATCMs to address air toxics from mobile and stationary sources. Some key ATCMs for stationary sources include reductions of benzene emissions from service stations, hexavalent chromium emissions from chrome plating, perchloroethylene emissions from dry cleaning, ethylene oxide emissions from sterilizers, and multiple air toxics from the automotive painting and repair industries.

Many of CARB's recent ATCMs are part of the CARB Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles (DRRP) which was adopted in September 2000 (http://www.arb.ca.gov/diesel/documents/rrpapp.htm) with the goal of reducing diesel particulate matter emissions from compression ignition engines and associated health risk by 75 percent by 2010 and 85 percent by 2020. The DRRP includes strategies to reduce emissions from new and existing engines through the use of ultra-low sulfur diesel fuel, add-on controls, and engine replacement. In addition to stationary source engines, the plan addresses diesel PM emissions from mobile sources such as trucks, buses, construction equipment, locomotives, and ships.

SCAQMD

SCAQMD has regulated criteria air pollutants using either a technology-based or an emissions limit approach. The technology-based approach defines specific control technologies that may be installed to reduce pollutant emissions. The emission limit approach establishes an emission limit, and allows industry to use any emission control equipment, as long as the emission requirements are met. The regulation of TACs often uses a health risk-based approach, but may also require a regulatory approach similar to criteria pollutants, as explained in the following subsections.

Rules and Regulations: Under the SCAQMD's toxic regulatory program there are 15 source-specific rules that target toxic emission reductions that regulate over 10,000 sources such as metal finishing, spraying operations, dry cleaners, film cleaning, gasoline dispensing, and diesel-fueled stationary engines to name a few. In addition, other source-specific rules targeting criteria pollutant reductions also reduce toxic emissions, such as SCAQMD Rule 461 – Gasoline Transfer and Dispensing, which reduces benzene emissions from gasoline dispensing and SCAQMD Rule 1124 – Aerospace Assembly and Component Manufacturing Operations, which reduces perchloroethylene, trichloroethylene, and methylene chloride emissions from aerospace operations.

New and modified sources of TACs in the district are subject to SCAQMD Rule 1401 - New Source Review of Toxic Air Contaminants and SCAQMD Rule 212 - Standards for Approving Permits. Rule 212 requires notification of the SCAQMD's intent to grant a permit to construct a significant project, defined as a new or modified permit unit located within 1000 feet of a school (a state law requirement under AB 3205), a new or modified permit unit posing an maximum individual cancer risk of one in one million (1×10^{-6}) or greater, or a new or modified facility with criteria pollutant emissions exceeding specified daily maximums. Distribution of notice is required to all addresses within a 1/4-mile radius, or other area deemed appropriate by the SCAQMD. Rule 1401 currently controls emissions of carcinogenic and non-carcinogenic (health effects other than cancer) air contaminants from new, modified and relocated sources by specifying limits on cancer risk and hazard index (explained further in the following discussion), respectively. Rule 1401 lists nearly 300 TACs that are evaluated during the SCAQMD's permitting process for new, modified or relocated sources. During the past decade, more than 80 compounds have been added or had risk values amended. The addition of diesel particulate matter from diesel-fueled internal combustion engines as a TAC in March 2008 was one of the most substantial amendments to the rule. SCAQMD Rule 1401.1 – Requirements for New and Relocated Facilities Near Schools, sets risk thresholds for new and relocated facilities near schools. The requirements are more stringent than those for other air toxics rules in order to provide additional protection to school children.

Air Toxics Control Plan: In March 2000, the SCAQMD Governing Board approved the Air Toxics Control Plan (ATCP) which was the first comprehensive plan in the nation to guide future toxic rulemaking and programs. The ATCP was developed to lay out the SCAQMD's air toxics control program which built upon existing federal, state, and local toxic control programs as well as co-benefits from implementation of State Implementation Plan (SIP) measures. The concept for the plan was an outgrowth of the Environmental Justice principles and the Environmental Justice Initiatives adopted by the SCAQMD Governing Board in October 1997. Monitoring studies and air toxics regulations that were created from these initiatives emphasized the need for a more systematic approach to reducing TACs. The intent of the plan was to reduce exposure to air toxics in an equitable and cost-effective manner that promotes clean, healthful air in the district. The plan proposed control strategies to reduce TACs in the district implemented between years 2000 and 2010 through cooperative efforts of the SCAQMD, local governments, CARB and USEPA.

2003 Cumulative Impact Reduction Strategies: The SCAQMD Governing Board approved a cumulative impacts reduction strategy in September 2003. The resulting 25 cumulative impacts strategies were a key element of the 2004 Addendum to the ATCP (see next section). The strategies included rules, policies, funding, education, and cooperation with other agencies. Some of the key SCAQMD accomplishments related to the cumulative impacts reduction strategies were:

- SCAQMD Rule 1401.1 - Requirements for New and Relocated Facilities Near Schools. which set more stringent health risk requirements for new and relocated facilities near schools
- SCAQMD Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, which established diesel PM emission limits and other requirements for diesel-fueled engines
- SCAQMD Rule 1469.1 – Spraying Operations Using Coatings Containing Chromium, which regulated chrome spraying operations
- SCAQMD Rule 410 – Odors From Transfer Stations and Material Recovery Facilities, which addresses odors from transfer stations and material recovery facilities
- Intergovernmental Review comment letters for CEQA documents

- SCAQMD's land use guidance document
- Additional protection in toxics rules for sensitive receptors, such as more stringent requirements for chrome plating operations and diesel engines located near schools

2004 Addendum to the ATCP: An addendum to the ATCP was adopted by the SCAQMD Governing Board in 2004 (referred to herein as the 2004 Addendum to the ATCP) and served as a status report regarding implementation of the various mobile and stationary source strategies in the 2000 ATCP and introduced new measures to further address air toxics. The main elements of the 2004 Addendum to the ATCP were to address the progress made in implementation of the 2000 ATCP control strategies; provide a historical perspective of air toxic emissions and current air toxic levels; incorporate the Cumulative Impact Reduction Strategies approved by the SCAQMD Governing Board in 2003 and additional measures identified in the 2003 AQMP; project future air toxic levels to the extent feasible; and, summarize future efforts to develop the next ATCP. Significant progress had been made in implementing most of the SCAQMD strategies from the 2000 ATCP and the 2004 Addendum to the ATCP. CARB has also made notable progress in mobile source measures via its Diesel Risk Reduction Plan, especially for goods movement related sources, while the USEPA continued to implement their air toxic programs applicable to stationary sources

Clean Communities Plan: On November 5, 2010, the SCAQMD Governing Board approved the 2010 Clean Communities Plan (CCP). The CCP was an update to the 2000 Air Toxics Control Plan (ATCP) and the 2004 Addendum. The objective of the 2010 CCP is to reduce the exposure to air toxics and air-related nuisances throughout the district, with emphasis on cumulative impacts. The elements of the 2010 CCP are community exposure reduction, community participation, communication and outreach, agency coordination, monitoring and compliance, source-specific programs, and nuisance. The centerpiece of the 2010 CCP is a pilot study through which the SCAQMD staff will work with community stakeholders to identify and develop solutions community-specific to air quality issues in two communities: 1) the City of San Bernardino; and, 2) Boyle Heights and surrounding areas.

Control of TACs under the Air Toxics "Hot Spots" Act: In October 1992, the SCAQMD Governing Board adopted public notification procedures for Phase I and II facilities. These procedures specify that AB 2588 facilities must provide public notice when exceeding the following risk levels:

- Maximum Individual Cancer Risk (MICR): greater than 10 in one million (10 x 10^{-6})
- Total Hazard Index (HI): greater than 1.0 for TACs except lead, or > 0.5 for lead

Public notice is to be provided by letters mailed to all addresses and all parents of children attending school in the impacted area. In addition, facilities must hold a public meeting and provide copies of the facility risk assessment in all school libraries and a public library in the impacted area.

The AB2588 Toxics "Hot Spots" Program is implemented through SCAQMD Rule 1402 – Control of Toxic Air Contaminants from Existing Sources. The SCAQMD continues to review health risk assessments submitted. Notification is required from facilities with a significant risk under the AB 2588 program based on their initial approved health risk assessments and will continue on an ongoing basis as additional and subsequent health risk assessments are reviewed and approved.

There are currently about 600 facilities in the SCAQMD's AB2588 program. Since 1992 when the state Health and Safety Code incorporated a risk reduction requirement in the program, the SCAQMD has reviewed and approved over 300 HRAs, 44 facilities were required to do a public notice, and 21 facilities were subject to risk reduction. Currently, over 96 percent of the facilities in the program have cancer risks below ten in a million and over 98 percent have acute and chronic hazard indices of less than one.

CEQA Intergovernmental Review Program: The SCAQMD staff, through its Intergovernmental Review (IGR) provides comments to lead agencies on air quality analyses and mitigation measures in CEQA documents. The following are some key programs and tools that have been developed more recently to strengthen air quality analyses, specifically as they relate to exposure of mobile source air toxics:

- SCAQMD's Mobile Source Committee approved the "Health Risk Assessment Guidance for Analyzing Cancer Risks from Mobile Source Diesel Emissions" (August 2002). This document provides guidance for analyzing cancer risks from diesel particulate matter from truck idling and movement (e.g., truck stops, warehouse and distribution centers, or transit centers), ship hotelling at ports, and train idling.

- CalEPA and CARB's "Air Quality and Land Use Handbook: A Community Health Perspective" (April 2005), provides recommended siting distances for incompatible land uses.

- Western Riverside Council of Governments Air Quality Task Force developed a policy document titled, "Good Neighbor Guidelines for Siting New and/or Modified Warehouse/Distribution Facilities" (September 2005). This document provides guidance to local government on preventive measures to reduce neighborhood exposure to TACs from warehousing facilities.

Environmental Justice: Environmental justice (EJ) has long been a focus of the SCAQMD. In 1990, the SCAQMD formed an Ethnic Community Advisory Group that has since been restructured as the Environmental Justice Advisory Group (EJAG). EJAG's mission is to advise and assist SCAQMD in protecting and improving public health in SCAQMD's most impacted communities through the reduction and prevention of air pollution.

In 1997, the SCAQMD Governing Board adopted four guiding principles and ten initiatives (http://www.aqmd.gov/ej/history.htm) to ensure environmental equity. Also in 1997, the SCAQMD Governing Board expanded the initiatives to include the "Children's

Air Quality Agenda" focusing on the disproportionate impacts of poor air quality on children. Some key initiatives that have been implemented were the Multiple Air Toxics Exposure Studies (MATES, MATES II and MATES III); the Clean Fleet Rules, the Cumulative Impacts strategies; funding for lower emitting technologies under the Carl Moyer Program; the Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning; a guidance document on Air Quality Issues in School Site Selection; and the 2000 ATCP and the 2004 Addendum to the ATCP. Key initiatives focusing on communities and residents include the Clean Air Congress; the Clean School Bus Program; Asthma and Air Quality Consortium; Brain and Lung Tumor and Air Pollution Foundation; air quality presentations to schools and community and civic groups; and Town Hall meetings. Technological and scientific projects and programs have been a large part of the SCAQMD's EJ program since its inception. Over time, the EJ program's focus on public education, outreach, and opportunities for public participation have greatly increased. Public education materials and other resources for the public are available on the SCAQMD's website (www.aqmd.gov).

AB 2766 Subvention Funds: AB2766 subvention funds are monies collected by the state as part of vehicle registration and passed through to the SCAQMD for funding projects of local cities, among others, that reduce motor vehicle air pollutants. The Clean Fuels Program, funded by a surcharge on motor vehicle registrations in the SCAQMD, reduces TAC emissions through co-funding projects to develop and demonstrate low-emission clean fuels and advanced technologies, and to promote commercialization and deployment of promising or proven technologies in Southern California.

Carl Moyer Program: Another program that targets diesel emission reductions is the Carl Moyer Program which provides grants for projects that achieve early or extra emission reductions beyond what is required by regulations. Examples of eligible projects include cleaner on-road, off-road, marine, locomotive, and stationary agricultural pump engines. Other endeavors of the SCAQMD's Technology Advancement Office help to reduce diesel PM emissions through co-funding research and demonstration projects of clean technologies, such as low-emitting locomotives.

Control of TACs with Risk Reduction Audits and Plans: SB 1731, enacted in 1992 and codified at HSC §44390 et seq., amended AB 2588 to include a requirement for facilities with significant risks to prepare and implement a risk reduction plan which will reduce the risk below a defined significant risk level within specified time limits. SCAQMD Rule 1402 was adopted on April 8, 1994 to implement the requirements of SB 1731.

In addition to the TAC rules adopted by SCAQMD under authority of AB 1807 and SB 1731, the SCAQMD has adopted source-specific TAC rules, based on the specific level of TAC emitted and the needs of the area. These rules are similar to the state's ATCMs because they are source-specific and only address emissions and risk from specific compounds and operations.

Multiple Air Toxics Exposure Studies (MATES): In 1986, SCAQMD conducted the first MATES Study to determine the Basin-wide risks associated with major airborne carcinogens. At the time, the state of technology was such that only twenty known air toxic compounds could be analyzed and diesel exhaust particulate did not have an agency accepted carcinogenic health risk value. TACs are determined by the USEPA, and by the CalEPA, including the Office of Environmental Health Hazard Assessment and the ARB. For purposes of MATES, the California carcinogenic health risk factors were used. The maximum combined individual health risk for simultaneous exposure to pollutants under the study was estimated to be 600 to 5,000 in one million.

Multiple Air Toxics Exposure Study II (MATES II): At its October 10, 1997 meeting, the SCAQMD Governing Board directed staff to conduct a follow up to the MATES study to quantify the magnitude of population exposure risk from existing sources of selected air toxic contaminants at that time. The follow up study, MATES II, included a monitoring program of 40 known air toxic compounds, an updated emissions inventory of TACs (including microinventories around each of the 14 microscale sites), and a modeling effort to characterize health risks from hazardous air pollutants. The estimated basin-wide carcinogenic health risk from ambient measurements was 1,400 per million people. About 70 percent of the basin wide health risk was attributed to diesel particulate emissions; about 20 percent to other toxics associated with mobile sources (including benzene, butadiene, and formaldehyde); about 10 percent of basin wide health risk was attributed to stationary sources (which include industrial sources and other certain specifically identified commercial businesses such as dry cleaners and print shops.)

Multiple Air Toxics Exposure Study III (MATES III): MATES III was a follow up to previous air toxics studies in the Basin and was part of the SCAQMD Governing Board's 2003-04 Environmental Justice Workplan. The MATES III Study consists of several elements including a monitoring program, an updated emissions inventory of TACs, and a modeling effort to characterize carcinogenic health risk across the Basin. Besides toxics, additional measurements include organic carbon, elemental carbon, and total carbon, as well as, PM, including PM2.5. It did not estimate mortality or other health effects from particulate exposures. MATES III revealed a general downward trend in air toxic pollutant concentrations with an estimated basin-wide lifetime carcinogenic health risk of 1,200 in one million. Mobile sources accounted for 94 percent of the basin-wide lifetime carcinogenic health risk with diesel exhaust particulate contributing to 84 percent of the mobile source basin-wide lifetime carcinogenic health risk. Non-diesel carcinogenic health risk declined by 50 percent from the MATES II values.

Multiple Air Toxics Exposure Study IV (MATES IV): Monitoring began in June 2012 and a Technical Advisory Group formed. The 10 sites from Mates III would continue to be monitored for trends in the data. A new focus of Mates IV is the inclusion of measurements of ultrafine particle concentrations and localized impacts of combustion sources. The focus of these measurements will be on assessing the exposures to ultrafine particles and black carbon very near sources such as airports, freeways, railyards, busy intersections and warehouse operations.

Carcinogenic Health Risks from Toxic Air Contaminants: One of the primary health risks of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a particular public health concern because it is currently believed by many scientists that there is no "safe" level of exposure to carcinogens. Any exposure to a carcinogen poses some risk of causing cancer. It is currently estimated that about one in four deaths in the U.S. is attributable to cancer. About two percent of cancer deaths in the U.S. may be attributable to environmental pollution (Doll and Peto 1981). The proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods.

Non-Cancer Health Risks from Toxic Air Contaminants: Unlike carcinogens, for most TAC non-carcinogens it is believed that there is a threshold level of exposure to the compound below which it will not pose a health risk. CalEPA's Office of Environmental Health Hazard Assessment (OEHHA) develops Reference Exposure Levels (RELs) for TACs which are health-conservative estimates of the levels of exposure at or below which health effects are not expected. The non-cancer health risk due to exposure to a TAC is assessed by comparing the estimated level of exposure to the REL. The comparison is expressed as the ratio of the estimated exposure level to the REL, called the hazard index (HI).

3.2.2.2 Climate Change

Global climate change is a change in the average weather of the earth, which can be measured by wind patterns, storms, precipitation, and temperature. Historical records have shown that temperature changes have occurred in the past, such as during previous ice ages. Data indicate that the current temperature record differs from previous climate changes in rate and magnitude.

Gases that trap heat in the atmosphere are often called greenhouse gases (GHGs), comparable to a greenhouse, which captures and traps radiant energy. GHGs are emitted by natural processes and human activities. The accumulation of greenhouse gases in the atmosphere regulates the earth's temperature. Global warming is the observed increase in average temperature of the earth's surface and atmosphere. The primary cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), and perfluorocarbon (PFCs). The GHGs absorb longwave radiant energy emitted by the Earth, which warms the atmosphere. The GHGs also emit longwave radiation both upward to space and back down toward the surface of the Earth. The downward part of this longwave radiation emitted by the atmosphere is known as the "greenhouse effect." Emissions from human activities such as fossil fuel combustion for electricity production and vehicles have elevated the concentration of these gases in the atmosphere.

CO2 is an odorless, colorless greenhouse gas. Natural sources include the following: decomposition of dead organic matter; respiration of bacteria, plants, animals, and fungus; evaporation from oceans; and volcanic outgassing. Anthropogenic (human caused) sources of CO2 include burning coal, oil, gasoline, natural gas, and wood.

CH4 is a flammable gas and is the main component of natural gas. N2O, also known as laughing gas, is a colorless greenhouse gas. Some industrial processes such as fossil fuel-fired power plants, nylon production, nitric acid production, and vehicle emissions also contribute to the atmospheric load of N2O. HFCs are synthetic man-made chemicals that are used as a substitute for chlorofluorocarbons (whose production was stopped as required by the Montreal Protocol) for automobile air conditioners and refrigerants. The two main sources of PFCs are primary aluminum production and semiconductor manufacture. SF6 is an inorganic, odorless, colorless, nontoxic, nonflammable gas. SF6 is used for insulation in electric power transmission and distribution equipment, in the magnesium industry, in semiconductor manufacturing, and as a tracer gas for leak detection.

Scientific consensus, as reflected in recent reports issued by the United Nations Intergovernmental Panel on Climate Change, is that the majority of the observed warming over the last 50 years can be attributable to increased concentration of GHGs in the atmosphere due to human activities. Industrial activities, particularly increased consumption of fossil fuels (e.g., gasoline, diesel, wood, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHGs. The United Nations Intergovernmental Panel on Climate Change constructed several emission trajectories of greenhouse gases needed to stabilize global temperatures and climate change impacts. It concluded that a stabilization of greenhouse gases at 400 to 450 ppm carbon dioxide-equivalent concentration is required to keep global mean warming below two degrees Celsius, which has been identified as necessary to avoid dangerous impacts from climate change.

The potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, air quality impacts, and sea level rise. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems (e.g., heat rash and heat stroke). In addition, climate sensitive diseases may increase, such as those spread by mosquitoes and other disease carrying insects. Those diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding, hurricanes, and wildfires can displace people and agriculture, which would have negative consequences. Drought in some areas may increase, which would decrease water and food availability. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.

The impacts of climate change will also affect projects in various ways. Effects of climate change are rising sea levels and changes in snow pack. The extent of climate change impacts at specific locations remains unclear. It is expected that Federal, State and local agencies will more precisely quantify impacts in various regions. As an example, it is expected that the California Department of Water Resources will formalize a list of foreseeable water quality issues associated with various degrees of climate change. Once state government agencies make these lists available, they could be used to more precisely determine to what extent a project creates global climate change impacts.

Federal

Greenhouse Gas Endangerment Findings: On December 7, 2009, the USEPA Administrator signed two distinct findings regarding greenhouse gases pursuant to CAA §202 (a). The Endangerment Finding stated that CO2, CH4, N2O, HFCs, PFCs, and SF6 taken in combination endanger both the public health and the public welfare of current and future generations. The *Cause or Contribute Finding* stated that the combined emissions from motor vehicles and motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare. These findings were a prerequisite for implementing GHG standards for vehicles. The USEPA and the National Highway Traffic Safety Administration (NHTSA) finalized emission standards for light-duty vehicles in May 2010 and for heavy-duty vehicles in August of 2011.

Renewable Fuel Standard: The Renewable Fuel Standard (RFS) program was established under the Energy Policy Act (EPAct) of 2005, and required 7.5 billion gallons of renewable-fuel to be blended into gasoline by 2012. Under the Energy Independence and Security Act (EISA) of 2007, the RFS program was expanded to include diesel, required the volume of renewable fuel blended into transportation fuel be increased from nine billion gallons in 2008 to 36 billion gallons by 2022, established new categories of renewable fuel and required USEPA to apply lifecycle GHG performance threshold standards so that each category of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces. The RFS is expected to reduce greenhouse gas emissions by 138 million metric tons[6], about the annual emissions of 27 million passenger vehicles, replacing about seven percent of expected annual diesel consumption and decreasing oil imports by $41.5 billion.

GHG Tailoring Rule: On May 13, 2010, USEPA finalized the GHG Tailoring Rule to phase in the applicability of the Prevention of Significant Deterioration (PSD) and Title V operating permit programs for GHGs. The GHG Tailoring Rule was tailored to include the largest GHG emitters, while excluding smaller sources (restaurants, commercial facilities and small farms). The first phase (from January 2, 2011 to June 30, 2011) addressed the largest sources that contributed 65 percent of the stationary GHG sources. Title V GHG requirements were triggered only when affected facility owners/operators were applying, renewing or revising their permits for non-GHG pollutants. PSD GHG requirements were applicable only if sources were undergoing permitting actions for other non-GHG pollutants and the permitted action would increase GHG emission by 75,000 metric tons of CO2 equivalent emissions (CO2e) per year or more.

The second phase (from July 1, 2011 to June 30, 2013) included sources that emit or have the potential to emit 100,000 of CO2e metric tons per year or more. Newly constructed sources that are not major sources for non-GHG pollutants would not be subject to PSD GHG requirements unless it emits 100,000 metric tons of CO2e per year or more. Modifications to a major source would not be subject to PSD GHG requirements unless it generates a net increase of 75,000 metric tons of CO2e per year or more. Sources not subject to Title V would not be subject to Title V GHG requirements unless 100,000 metric tons of CO2e per year or more would be emitted.

[6] One metric ton is equal to 2, 205 pounds.

The third phase of the GHG Tailoring Rule, finalized on July 12, 2012, determined not to lower the current PSD and Title V applicability thresholds for GHG-emitting sources established in the GHG Tailoring Rule for phases 1 and 2. The GHG Tailoring Rule also promulgated regulatory revisions for better implementation of the federal program for establishing plantwide applicability limitations (PALs) for GHG emissions, which will improve the administration of the GHG PSD permitting programs. Recently, the U.S. Supreme Court held that EPA was limited to Step 1.

GHG Reporting Program: USEPA issued the Mandatory Reporting of Greenhouse Gases Rule (40 CFR Part 98) under the 2008 Consolidated Appropriations Act. The Mandatory Reporting of Greenhouse Gases Rule requires reporting of GHG data from large sources and suppliers under the Greenhouse Gas Reporting Program (GHGRP). Suppliers of certain products that would result in GHG emissions if released, combusted or oxidized; direct emitting source categories; and facilities that inject CO2 underground for geologic sequestration or any purpose other than geologic sequestration are included. Facilities that emit 25,000 metric tons or more per year of GHGs as CO2e are required to submit annual reports to USEPA. For the 2010 calendar, there were 6,260 entities that reported GHG data under this program, and 467 of the entities were from California. Of the 3,200 million metric tons of CO2e that were reported nationally, 112 million metric tons of CO2e were from California. Power plants were the largest stationary source of direct U.S. GHG emissions with 2,326 million metric tons of CO2e, followed by refineries with 183 million metric tons of CO2e. CO2 emissions accounted for largest share of direct emissions with 95 percent, followed by CH4 with four percent, and N2O and fluorinated gases representing the remaining one percent.

State

Executive Order S-3-05: In June 2005, Governor Schwarzenegger signed Executive Order S-3-05, which established emission reduction targets. The goals would reduce GHG emissions to 2000 levels by 2010, then to 1990 levels by 2020, and to 80 percent below 1990 levels by 2050.

AB 32 - Global Warming Solutions Act: On September 27, 2006, AB 32, the California Global Warming Solutions Act of 2006, was signed by Governor Schwarzenegger. AB 32 expanded on Executive Order S-3-05. The California legislature stated that “global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California.” AB 32 represents the first enforceable state-wide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national and international actions will be necessary to fully address the issue of global warming, AB 32 lays out a program to inventory and reduce greenhouse gas emissions in California and from power generation facilities located outside the state that serve California residents and businesses. AB 32 requires CARB to:

- Establish a statewide GHG emissions cap for 2020, based on 1990 emissions by January 1, 2008;

- Adopt mandatory reporting rules for significant sources of GHG by January 1, 2008;
- Adopt a GHG emissions reduction plan by January 1, 2009, indicating how the GHG emissions reductions will be achieved via regulations, market mechanisms, and other actions; and
- Adopt regulations to achieve the maximum technologically feasible and cost-effective reductions of GHG by January 1, 2011.

The combination of Executive Order S-3-05 and AB 32 will require significant development and implementation of energy efficient technologies and shifting of energy production to renewable sources.

Consistent with the requirement to develop an emission reduction plan, CARB prepared a Scoping Plan indicating how GHG emission reductions will be achieved through regulations, market mechanisms, and other actions. The Scoping Plan was released for public review and comment in October 2008 and approved by CARB on December 11, 2008. The Scoping Plan calls for reducing GHG emissions to 1990 levels by 2020. This means cutting approximately 30 percent from business-as-usual (BAU) emission levels projected for 2020, or about 15 percent from today's levels. Key elements of CARB staff's recommendations for reducing California's GHG emissions to 1990 levels by 2020 contained in the Scoping Plan include the following:

- Expansion and strengthening of existing energy efficiency programs and building and appliance standards;
- Expansion of the Renewables Portfolio Standard to 33 percent;
- Development of a California cap-and-trade program that links with other Western Climate Initiative (WCI) partner programs to create a regional market system;
- Establishing targets for transportation-related greenhouse gases and pursuing policies and incentives to achieve those targets;
- Adoption and implementation of existing state laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard (LCFS); and
- Targeted fees, including a public good charge on water use, fees on high global warming potential (GWP) gases and a fee to fund the state's long-term commitment to AB 32 administration.

In response to the comments received on the Draft Scoping Plan and at the November 2008 public hearing, CARB made a few changes to the Draft Scoping Plan, primarily to:

- State that California "will transition to 100 percent auction" of allowances and expects to "auction significantly more [allowances] than the Western Climate Initiative minimum;"

- Make clear that allowance set-asides could be used to provide incentives for voluntary renewable power purchases by businesses and individuals and for increased energy efficiency;

- Make clear that allowance set-asides can be used to ensure that voluntary actions, such as renewable power purchases, can be used to reduce greenhouse gas emissions under the cap;

- Provide allowances are not required from carbon neutral projects; and

- Mandate that commercial recycling be implemented to replace virgin raw materials with recyclables.

SB 97 – CEQA, Greenhouse Gas Emissions: On August 24, 2007, Governor Schwarzenegger signed into law SB 97 – CEQA: Greenhouse Gas Emissions, and stated, "This bill advances a coordinated policy for reducing greenhouse gas emissions by directing the Office of Planning and Research (OPR) and the Resources Agency to develop CEQA guidelines on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions." As directed by SB 97, the Natural Resources Agency adopted amendments to the CEQA Guidelines for GHG emissions on December 30, 2009 to provide guidance to public agencies regarding the analysis and mitigation of the effects of GHG emissions in draft CEQA documents. The amendments did not establish a threshold for significance for GHG emissions. The amendments became effective on March 18, 2010.

***OPR - Technical Advisory on CEQA and Climate Change*:** Consistent with SB 97, on June 19, 2008, OPR released its "Technical Advisory on CEQA and Climate Change," which was developed in cooperation with the Resources Agency, the CalEPA, and the CARB. According to OPR, the "Technical Advisory" offers the informal interim guidance regarding the steps lead agencies should take to address climate change in their CEQA documents, until CEQA guidelines are developed pursuant to SB 97 on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions.

According to OPR, lead agencies should determine whether greenhouse gases may be generated by a proposed project, and if so, quantify or estimate the GHG emissions by type and source. Second, the lead agency must assess whether those emissions are individually or cumulatively significant. When assessing whether a project's effects on climate change are "cumulatively considerable" even though its GHG contribution may be individually limited, the lead agency must consider the impact of the project when viewed in connection with the effects of past, current, and probable future projects. Finally, if the lead agency determines that the GHG emissions from the project as proposed are potentially significant, it must investigate and implement ways to avoid, reduce, or otherwise mitigate the impacts of those emissions.

In 2009, total California greenhouse gas emissions were 457 million metric tons of CO2e (MMTCO2e); net emissions were 453 MMTCO2e, reflecting the influence of sinks (net

CO2 flux from forestry). While total emissions have increased by 5.5 percent from 1990 to 2009, emissions decreased by 5.8 percent from 2008 to 2009 (485 to 457 MMTCO2e). The total net emissions between 2000 and 2009 decreased from 459 to 453 MMTCO2e, representing a 1.3 percent decrease from 2000 and a 6.1 percent increase from the 1990 emissions level. The transportation sector accounted for approximately 38 percent of the total emissions, while the industrial sector accounted for approximately 20 percent. Emissions from electricity generation were about 23 percent with almost equal contributions from in-state and imported electricity.

Per capita emissions in California have slightly declined from 2000 to 2009 (by 9.7 percent), but the overall nine percent increase in population during the same period offsets the emission reductions. From a per capita sector perspective, industrial per capita emissions have declined 21 percent from 2000 to 2009, while per capita emissions for ozone depleting substance (ODS) substitutes saw the highest increase (52 percent).

From a broader geographical perspective, the state of California ranked second in the U.S. for 2007 greenhouse gas emissions, only behind Texas. However, from a per capita standpoint, California had the 46th lowest GHG emissions. On a global scale, California had the 14th largest carbon dioxide emissions and the 19th largest per capita emissions. The GHG inventory is divided into three categories: stationary sources, on-road mobile sources, and off-road mobile sources.

AB 1493 Vehicular Emissions - CO2: Prior to the USEPA and NHTSA joint rulemaking, Governor Schwarzenegger signed Assembly Bill AB 1493 (2002). AB 1493 requires that CARB develop and adopt, by January 1, 2005, regulations that achieve "the maximum feasible reduction of greenhouse gases emitted by passenger vehicles and light-duty trucks and other vehicles determined by CARB to be vehicles whose primary use is noncommercial personal transportation in the state."

CARB originally approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations to take effect in 2009 (see amendments to CCR Title 13 §§1900 and 1961 (13 CCR 1900, 1961), and the adoption of CCR Title 13 §1961.1 (13 CCR 1961.1)). California's first request to the USEPA to implement GHG standards for passenger vehicles was made in December 2005 and subsequently denied by the USEPA in March 2008. The USEPA then granted California the authority to implement GHG emission reduction standards for new passenger cars, pickup trucks and sport utility vehicles on June 30, 2009.

On April 1, 2010, CARB filed amended regulations for passenger vehicles as part of California's commitment toward the national program to reduce new passenger vehicle GHGs from 2012 through 2016. The amendments will prepare California to harmonize its rules with the federal Light-Duty Vehicle GHG Standards and CAFE Standards.

SB 1368: SB 1368 is the companion bill of AB 32 and was signed by Governor Schwarzenegger in September 2006. SB 1368 required the CPUC to establish a GHG emission performance standard for baseload generation from investor owned utilities by February 1, 2007. The CEC was also required to establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the greenhouse gas emission rate from a baseload combined-cycle natural gas fired plant. The legislation further required that all electricity provided to California, including imported electricity, must be generated from plants that meet the standards set by the PUC and CEC.

Executive Order S-1-07: Governor Schwarzenegger signed Executive Order S-1-07 in 2007 which established the transportation sector as the main source of GHG emissions in California. Executive Order S-1-07 proclaims that the transportation sector accounts for over 40 percent of statewide GHG emissions. Executive Order S-1-07 also establishes a goal to reduce the carbon intensity of transportation fuels sold in California by a minimum of 10 percent by 2020.

In particular, Executive Order S-1-07 established the LCFS and directed the Secretary for Environmental Protection to coordinate the actions of the CEC, CARB, the University of California, and other agencies to develop and propose protocols for measuring the "life-cycle carbon intensity" of transportation fuels. The analysis supporting development of the protocols was included in the SIP for alternative fuels (State Alternative Fuels Plan adopted by CEC on December 24, 2007) and was submitted to CARB for consideration as an "early action" item under AB 32. CARB adopted the LCFS on April 23, 2009.

SB 375: SB 375, signed into law in September 2008, aligns regional transportation planning efforts, regional GHG reduction targets, and land use and housing allocation. As part of the alignment, SB 375 requires Metropolitan Planning Organizations (MPOs) to adopt a Sustainable Communities Strategy (SCS) or Alternative Planning Strategy (APS) which prescribes land use allocation in that MPO's Regional Transportation Plan (RTP). CARB, in consultation with MPOs, is required to provide each affected region with reduction targets for GHGs emitted by passenger cars and light trucks in the region for the years 2020 and 2035. These reduction targets will be updated every eight years but can be updated every four years if advancements in emissions technologies affect the reduction strategies to achieve the targets. CARB is also charged with reviewing each MPO's SCS or APS for consistency with its assigned GHG emission reduction targets. If MPOs do not meet the GHG reduction targets, transportation projects located in the MPO boundaries would not be eligible for funding programmed after January 1, 2012.

CARB appointed the Regional Targets Advisory Committee (RTAC), as required under SB 375, on January 23, 2009. The RTAC's charge was to advise CARB on the factors to be considered and methodologies to be used for establishing regional targets. The RTAC provided its recommendation to CARB on September 29, 2009. CARB was required to adopt final targets by September 30, 2010.

Executive Order S-13-08: Governor Schwarzenegger signed Executive Order S-13-08 on November 14, 2008 which directed California to develop methods for adapting to climate change through preparation of a statewide plan. Executive Order S-13-08 directed OPR, in cooperation with the Resources Agency, to provide land use planning guidance related to sea level rise and other climate change impacts by May 30, 2009. Executive Order S-13-08 also directed the Resources Agency to develop a state Climate Adaptation Strategy by June 30, 2009 and to convene an independent panel to complete the first California Sea Level Rise Assessment Report. The assessment report was required to be completed by December 1, 2010 and required to meet the following four criteria:

1. Project the relative sea level rise specific to California by taking into account issues such as coastal erosion rates, tidal impacts, El Niño and La Niña events, storm surge, and land subsidence rates;
2. Identify the range of uncertainty in selected sea level rise projections;
3. Synthesize existing information on projected sea level rise impacts to state infrastructure (e.g., roads, public facilities, beaches), natural areas, and coastal and marine ecosystems; and
4. Discuss future research needs relating to sea level rise in California.

SB 1078, SB 107 and Executive Order S-14-08: SB 1078 (Chapter 516, Statutes of 2002) requires retail sellers of electricity, including investor owned utilities and community choice aggregators, to provide at least 20 percent of their supply from renewable sources by 2017. SB 107 (Chapter 464, Statutes of 2006) changed the target date to 2010. In November 2008, Governor Schwarzenegger signed Executive Order S-14-08, which expands the state's Renewable Portfolio Standard to 33 percent renewable power by 2020.

SB X-1-2: SB X1-2 was signed by Governor Brown in April 2011. SB X1-2 created a new Renewables Portfolio Standard (RPS), which pre-empted CARB's 33 percent Renewable Electricity Standard. The new RPS applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. These entities must adopt the new RPS goals of 20 percent of retails sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirement by the end of 2020.

<u>SCAQMD</u>

The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy commits the SCAQMD to consider global impacts in rulemaking and in drafting revisions to the AQMP. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include support of the adoption of a California GHG emission reduction goal.

Basin GHG Policy and Inventory: The SCAQMD has established a policy, adopted by the SCAQMD Governing Board at its September 5, 2008 meeting, to actively seek opportunities to reduce emissions of criteria, toxic, and climate change pollutants. The policy includes the intent to assist businesses and local governments implementing climate change measures, decrease the agency's carbon footprint, and provide climate change information to the public. The SCAQMD will take the following actions:

1. Work cooperatively with other agencies/entities to develop quantification protocols, rules, and programs related to greenhouse gases;

2. Share experiences and lessons learned relative to SCAQMD Regulation XX - Regional Clean Air Incentives Market (RECLAIM), to help inform state, multi-state, and federal development of effective, enforceable cap-and-trade programs. To the extent practicable, staff will actively engage in current and future regulatory development to ensure that early actions taken by local businesses to reduce greenhouse gases will be treated fairly and equitably. SCAQMD staff will seek to streamline administrative procedures to the extent feasible to facilitate the implementation of AB 32 measures;
3. Review and comment on proposed legislation related to climate change and greenhouse gases, pursuant to the 'Guiding Principles for SCAQMD Staff Comments on Legislation Relating to Climate Change' approved at the SCAQMD Governing Board's Special Meeting in April 2008;
4. Provide higher priority to funding Technology Advancement Office (TAO) projects or contracts that also reduce greenhouse gas emissions;
5. Develop recommendations through a public process for an interim greenhouse gas CEQA significance threshold, until such time that an applicable and appropriate statewide greenhouse gas significance level is established. Provide guidance on analyzing greenhouse gas emissions and identify mitigation measures. Continue to consider GHG impacts and mitigation in SCAQMD lead agency documents and in comments when SCAQMD is a responsible agency;
6. Revise the SCAQMD's Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning to include information on greenhouse gas strategies as a resource for local governments. The Guidance Document will be consistent with state guidance, including CARB's Scoping Plan;
7. Update the Basin's greenhouse gas inventory in conjunction with each Air Quality Management Plan. Information and data used will be determined in consultation with CARB, to ensure consistency with state programs. Staff will also assist local governments in developing greenhouse gas inventories;
8. Bring recommendations to the SCAQMD Governing Board on how the agency can reduce its own carbon footprint, including drafting a Green Building Policy with recommendations regarding SCAQMD purchases, building maintenance, and other areas of products and services. Assess employee travel as well as other activities that are not part of a GHG inventory and determine what greenhouse gas emissions these activities represent, how they could be reduced, and what it would cost to offset the emissions;
9. Provide educational materials concerning climate change and available actions to reduce greenhouse gas emissions on the SCAQMD website, in brochures, and other venues to help cities and counties, businesses, households, schools, and others learn about ways to reduce their electricity and water use through conservation or other efforts, improve energy efficiency, reduce vehicle miles traveled, access alternative mobility resources, utilize low emission vehicles and implement other climate friendly strategies; and

10. Conduct conferences, or include topics in other conferences, as appropriate, related to various aspects of climate change, including understanding impacts, technology advancement, public education, and other emerging aspects of climate change science.

On December 5, 2008, the SCAQMD Governing Board adopted the staff proposal for an interim GHG significance threshold for projects where the SCAQMD is lead agency. SCAQMD's recommended interim GHG significance threshold proposal uses a tiered approach to determining significance. Tier 1 consists of evaluating whether or not the project qualifies for any applicable exemption under CEQA. Tier 2 consists of determining whether or not the project is consistent with a GHG reduction plan that may be part of a local general plan, for example. Tier 3 establishes a screening significance threshold level to determine significance using a 90 percent emission capture rate approach, which corresponds to 10,000 metric tons of CO2 equivalent emissions per year (MTCO2e/year). Tier 4, to be based on performance standards, is yet to be developed. Under Tier 5 the project proponent would allow offsets to reduce GHG emission impacts to less than the proposed screening level. If CARB adopts statewide significance thresholds, SCAQMD staff plans to report back to the SCAQMD Governing Board regarding any recommended changes or additions to the SCAQMD's interim threshold.

Table 3.2-3 presents the GHG emission inventory by major source categories in calendar year 2008, as identified in the 2012 AQMP for the South Coast Air Basin. The emissions reported herein are based on in-basin energy consumption and do not include out-of-basin energy production (e.g., power plants, crude oil production) or delivery emissions (e.g., natural gas pipeline loss). Three major GHG pollutants have been included: CO2, N2O, and CH4. These GHG emissions are reported in MMTCO2e. Mobile sources generate 59.4 percent of the emissions, and include airport equipment, and oil and gas drilling equipment. The remaining 40.6 percent of the total Basin GHG emissions are from stationary and area sources. The largest stationary/area source is fuel combustion, which is 27.8 percent of the total Basin GHG emissions (68.6 percent of the GHG emissions from the stationary and area source category).

3.2.2.3 Air Quality – Ozone Depletion

The Montreal Protocol on Substances that Deplete the Ozone Layer (Montreal Protocol) is an international treaty designed to phase out halogenated hydrocarbons such as chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), which are considered ODSs. The Montreal Protocol was first signed in September 16, 1987 and has been revised seven times. The U.S. ratified the original Montreal Protocol and each of its revisions.

Federal

Under the CAA Title VI, the USEPA is assigned responsibility for implementing programs that protect the stratospheric ozone layer. 40 CFR Part 82 contains USEPA's regulations specific to protecting the ozone layer. These USEPA regulations phase out the production and import of ozone depleting substances (ODSs) consistent with the Montreal Protocol. ODSs are typically used as refrigerants or as foam blowing agents. ODS are regulated as Class I or Class II controlled substances. Class I substances have a higher ozone-depleting potential and have been completely phased out in the U.S., except for exemptions allowed under the Montreal Protocol. Class II substances are HCFCs, which are transitional substitutes for many Class I substances and are being phased out.

TABLE 3.2-3
2008 GHG Emissions for the South Coast Air Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
	Fuel Combustion							
10	Electric Utilities	34,303	.08	0.71	12,520,562	29.0	258	11.4
20	Cogeneration	872	.00	0.02	318,340	0.60	6.00	0.29
30	Oil and Gas Production (combustion)	2,908	.01	0.08	1,061,470	4.71	29.5	0.96
40	Petroleum Refining (Combustion)	44,654	.06	0.57	16,298,766	20.7	207	14.8
50	Manufacturing and Industrial	22,182	.06	0.48	8,096,396	20.9	174	7.35
52	Food and Agricultural Processing	927	00	0.02	338,516	0.84	7.16	0.31
60	Service and Commercial	21,889	0.08	0.59	7,989,416	30.8	215	7.26
99	Other (Fuel Combustion)	2,241	0.2	0.16	818,057	8.58	58	0.75
Total Fuel Combustion		**129,977**	**0.32**	**2.62**	**47,441,523**	**116**	**956**	**43.1**
	Waste Disposal							
110	Sewage Treatment	26.4	0.00	0.00	9,653	0.12	1.50	0.01
120	Landfills	3,166	0.04	505	1,155,509	14.0	184,451	4.57
130	Incineration	580	0.00	0.02	211,708	0.81	5.48	0.19
199	Other (Waste Disposal)			2.25	0	0.00	820	0.02
Total Waste Disposal		**3,772**	**0.04**	**508**	**1,376,870**	**14.9**	**185,278**	**4.78**
	Cleaning and Surface Coatings							
210	Laundering							
220	Degreasing							
230	Coatings and Related Processes	27.1	0.00	0.21	9,890	0.02	78.0	0.01
240	Printing			0.00	0	0.00	0.00	0.00
250	Adhesives and Sealants			0.00	0	0.00	0.00	0.00
299	Other (Cleaning and Surface Coatings)	2,621	0.00	0.12	956,739	1.20	43.9	0.87
Total Cleaning and Surface Coatings		**2,648**	**0.00**	**0.33**	**966,628**	**1.22**	**122**	**0.88**
	Petroleum Production and Marketing							
310	Oil and Gas Production	92.1	0.00	0.92	33,605	0.06	336	0.04
320	Petroleum Refining	770	0.00	1.65	280,932	0.36	603	0.27
330	Petroleum Marketing			83.8	0	0.00	30,598	0.58
399	Other (Petroleum Production and Marketing)			0.00	0	0.00	0	0.00
Total Petroleum Production and Marketing		**862**	**0.00**	**86.4**	**314,536**	**0.42**	**31,537**	**0.89**

TABLE 3.2-3 (Continued)
2008 GHG Emissions for the South Coast Air Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
	Industrial Processes							
410	Chemical			0.92	0	0.00	337	0.01
420	Food and Agriculture			0.02	0	0.00	7.10	0.00
430	Mineral Processes	279	0.00	0.05	101,804	0.19	17.3	0.09
440	Metal Processes			0.02	0	0.00	9.10	0.00
450	Wood and Paper			0.00	0	0.00	0.00	0.00
460	Glass and Related Products			0.00	0	0.00	0.90	0.00
470	Electronics			0.00	0	0.00	0.00	0.00
499	Other (Industrial Processes)	0.08	0.00	0.47	28	0.00	172	0.00
	Total Industrial Processes	**279**	**0.00**	**1.49**	**101,832**	**0.19**	**543**	**0.10**
	Solvent Evaporation							
510	Consumer Products			0.00	0.00	0.00	0.00	0.00
520	Architectural Coatings and Related Solvent			0.00	0.00	0.00	0.00	0.00
530	Pesticides/Fertilizers			0.00	0.00	0.00	0.00	0.00
540	Asphalt Paving/Roofing			0.07	0.00	0.00	24.20	0.00
	Total Solvent Evaporation	**0.00**	**0.00**	**0.07**	**0.00**	**0.00**	**24.20**	**0.00**
	Miscellaneous Processes							
610	Residential Fuel Combustion	38,850	0.12	0.95	14,180,326	45.3	347	12.9
620	Farming Operations			25.6	0.00	0.00	9,354	0.18
630	Construction and Demolition			0.00	0.00	0.00	0	0.00
640	Paved Road Dust			0.00	0.00	0.00	0	0.00
645	Unpaved Road Dust			0.00	0.00	0.00	0	0.00
650	Fugitive Windblown Dust			0.00	0.00	0.00	0	0.00
660	Fires			0.08	0.00	0.00	30.9	0.00
670	Waste Burning and Disposal			0.58	0.00	0.00	212	0.00
680	Utility Equipment				0.00	0.00		0.00
690	Cooking			0.64	0.00	0.00	235	0.00
699	Other (Miscellaneous Processes			0.00	0.00	0.00	0	0.00
	Total Miscellaneous Processes	**38,850**	**0.12**	**27.9**	**14,180,326**	**45.3**	**10,179**	**13.1**

TABLE 3.2-3 (Concluded)
2008 GHG Emissions for the South Coast Air Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
On-Road Motor Vehicles								
710	Light Duty Passenger Auto (LDA)	84,679	2.72	3.62	30,907,957	993	1,321	28.3
722	Light Duty Trucks 1 (T1 : up to 3750 lb.)	22,319	0.72	0.96	8,146,321	263	350	7.47
723	Light Duty Trucks 2 (T2 : 3751-5750 lb.)	33,495	1.08	1.43	12,225,619	392	523	11.2
724	Medium Duty Trucks (T3 : 5751-8500 lb.)	29,415	0.94	1.25	10,736,309	343	456	9.85
732	Light Heavy Duty Gas Trucks 1 (T4 : 8501-10000 lb.)	8,195	0.16	0.21	2,991,059	57.3	76.7	2.73
733	Light Heavy Duty Gas Trucks 2 (T5 : 10001-14000 lb.)	1,116	0.05	0.07	407,174	19.0	25.6	0.38
734	Medium Heavy Duty Gas Trucks (T6 : 14001-33000 lb.)	727	0.02	0.20	265,506	5.48	73.0	0.24
736	Heavy Heavy Duty Gas Trucks ((HHDGT > 33000 lb.)	102	0.01	0.01	37,198	2.19	2.56	0.03
742	Light Heavy Duty Diesel Trucks 1 (T4 : 8501-10000 lb.)	2,166	0.02	0.02	790,600	6.94	7.30	0.72
743	Light Heavy Duty Diesel Trucks 2 (T5 : 10001-14000 lb.)	735	0.01	0.01	268,413	2.56	2.92	0.24
744	Medium Heavy Duty Diesel Truck (T6 : 14001-33000 lb.)	5,422	0.02	0.02	1,978,974	8.40	8.76	1.80
746	Heavy Heavy Duty Diesel Trucks (HHDDT > 33000 lb.)	17,017	0.05	0.05	6,211,247	17.5	16.4	5.64
750	Motorcycles (MCY)	7,959	0.26	0.34	2,904,910	94.9	124	2.66
760	Diesel Urban Buses (UB)	2,135	0.00	0.00	779,389	1.46	1.46	0.71
762	Gas Urban Buses (UB)	166	0.02	0.02	60,654	8.40	6.94	0.06
770	School Buses (SB)	337	0.00	0.00	122,995	1.46	1.46	0.11
776	Other Buses (OB)	927	0.00	0.00	338,430	0.73	0.73	0.31
780	Motor Homes (MH)	568	0.03	0.04	207,431	11.0	14.6	0.19
Total On-Road Motor Vehicles		**217,480**	**6.11**	**8.26**	**79,380,188**	**155**	**187**	**72.7**
Other Mobile Sources								
810	Aircraft	37,455	0.10	0.09	13,670,930	36.5	31.8	12.4
820	Trains	586	0.00	0.00	213,835	0.45	1.38	0.19
830	Ships and Commercial Boats	3,452	0.01	0.02	1,259,927	2.64	8.13	1.14
	Other Off-road sources (construction equipment, airport equipment, oil and gas drilling equipment)	16,080	1.72	8.84	5,869,123	628	3,226	5.56
Total Other Mobile Sources		**57,572**	**1.83**	**8.95**	**21,013,816**	**668**	**3,268**	**19.3**
Total Stationary and Area Sources		**176,388**	**0.49**	**626**	**64,381,716**	**178**	**228,639**	**63**
Total On-Road Vehicles		**217,480**	**6.11**	**8.26**	**79,380,188**	**155**	**187**	**73**
Total Other Mobile*		**57,572**	**1.83**	**8.95**	**21,013,816**	**668**	**3,268**	**19**
Total 2008 Baseline GHG Emissions for Basin		**451,440**	**8.42**	**644**	**164,775,719**	**1,001**	**232,094**	**155**

State

AB 32 - Global Warming Solutions Act: Some ODSs exhibit high global warming potentials. CARB developed a cap and trade regulation under AB 32. The cap and trade regulation includes the Compliance Offset Protocol Ozone Depleting Substances Projects, which provides methods to quantify and report GHG emission reductions associated with the destruction of high global warming potential ODS sourced from and destroyed within the U.S. that would have otherwise been released to the atmosphere. The protocol must be used to quantify and report GHG reductions under the ARB's GHG Cap and Trade Regulation.

Refrigerant Management Program: As part implementing AB 32, CARB also adopted a Refrigerant Management Program in 2009. The Refrigerant Management Program is designed to reduce GHG emissions from stationary sources through refrigerant leak detection and monitoring, leak repair, system retirement and retrofitting, reporting and recordkeeping, and proper refrigerant cylinder use, sale, and disposal.

HFC Emission Reduction Measures for Mobile Air Conditioning - Regulation for Small Containers of Automotive Refrigerant: The Regulation for Small Containers of Automotive Refrigerant applies to the sale, use, and disposal of small containers of automotive refrigerant with a GWP greater than 150. Emission reductions are achieved through implementation of four requirements: 1) use of a self-sealing valve on the container, 2) improved labeling instructions, 3) a deposit and recycling program for small containers, and 4) an education program that emphasizes best practices for vehicle recharging. This regulation went into effect on January 1, 2010 with a one-year sell-through period for containers manufactured before January 1, 2010. The target recycle rate is initially set at 90 percent, and rose to 95 percent beginning January 1, 2012.

SCAQMD

The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy targeted a transition away from CFCs as an industrial refrigerant and propellant in aerosol cans. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include the following directives for ODSs:

- phase out the use and corresponding emissions of CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), carbon tetrachloride, and halons by December 1995;
- phase out the large quantity use and corresponding emissions of HCFCs by the year 2000;
- develop recycling regulations for HCFCs; and
- develop an emissions inventory and control strategy for methyl bromide.

SCAQMD Rule 1122 – Solvent Degreasers: SCAQMD Rule 1122 applies to all persons who own or operate batch-loaded cold cleaners, open-top vapor degreasers, all types of conveyorized degreasers, and air-tight and airless cleaning systems that carry out solvent degreasing operations with a solvent containing VOCs or with a NESHAP halogenated solvent. Some ODSs such as carbon tetrachloride and TCA are NESHAP halogenated solvents.

SCAQMD Rule 1171 – Solvent Cleaning Operations: SCAQMD Rule 1171 reduces emissions of VOCs, TACs, and stratospheric ozone-depleting or globalwarming compounds from the use, storage and disposal of solvent cleaning materials in solvent cleaning operations and activities

SCAQMD Rule 1411 - Recovery or Recycling of Refrigerants from Motor Vehicle Air Conditioners: Rule 1411 prohibits release or disposal of refrigerants used in motor vehicle air conditioners and prohibits the sale of refrigerants in containers which contain less than 20 pounds of refrigerant.

SCAQMD Rule 1415 - Reduction of Refrigerant Emissions from Stationary Air Conditioning Systems: Rule 1415 reduces emissions of high-global warming potential refrigerants from stationary air conditioning systems by requiring persons subject to this rule to reclaim, recover, or recycle refrigerant and to minimize refrigerant leakage.

SCAQMD Rule 1418 - Halon Emissions from Fire Extinguishing Equipment: Rule 1418 reduce halon emissions by requiring the recovery and recycling of halon from fire extinguishing systems, by limiting the use of halon to specified necessary applications, and by prohibiting the sale of portable halon fire extinguishers that contain less than five pounds of halon.

SUBCHAPTER 3.3

ENERGY

Regulatory Setting

Energy Trends in General (Statewide)

Alternative Clean Transportation Fuels

Renewable Energy

Consumptive Uses

3.3 ENERGY

This subchapter describes existing regulatory setting relative energy production and demand, including alternative and renewable fuels, and trends within California and the SCAQMD.

3.3.1 Regulatory Setting

Federal and state agencies regulate energy use and consumption through various means and programs. On the federal level, the United States Department of Transportation (USDOT), United States Department of Energy (USDOE), and United States Environmental Protection Agency (USEPA) are three agencies with substantial influence over energy policies and programs. Generally, federal agencies influence transportation energy consumption through establishment and enforcement of fuel economy standards for automobiles and light trucks, through funding of energy related research and development projects, and through funding for transportation infrastructure projects.

On the state level, the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) are two agencies with authority over different aspects of energy. The CPUC regulates privately-owned utilities in the energy, rail, passenger transportation, telecommunications, and water fields. The CEC collects and analyzes energy-related data, prepares state-wide energy policy recommendations and plans, promotes and funds energy efficiency and renewable energy resources programs, plans and directs state response to energy emergencies, and regulates the power plant siting and transmission process. Some of the more relevant federal and state transportation-energy-related laws and plans are discussed in the following subsections.

3.3.1.1 Federal Regulations

Energy Policy and Conservation Act

The Energy Policy and Conservation Act of 1975 sought to ensure that all vehicles sold in the U.S. would meet certain fuel economy goals. Through this Act, Congress established the first fuel economy standards for on-road motor vehicles in the U.S. Pursuant to the Act, the National Highway Traffic and Safety Administration, which is part of the USDOT, is responsible for establishing additional vehicle standards and for revising existing standards. Since 1990, the fuel economy standard for new passenger cars has been 27.5 miles per gallon. Since 1996, the fuel economy standard for new light trucks (gross vehicle weight of 8,500 pounds or less) has been 20.7 miles per gallon. Heavy-duty vehicles (e.g., vehicles and trucks over 8,500 pounds gross vehicle weight) are not currently subject to fuel economy standards. Compliance with federal fuel economy standards is not determined for each individual vehicle model, but rather, compliance is determined on the basis of each manufacturer's average fuel economy for the portion of their vehicles produced for sale in the U.S. The Corporate Average Fuel Economy (CAFE) program, which is administered by USEPA, was created to determine vehicle manufacturers' compliance with the fuel economy standards. The USEPA calculates a CAFE value for each manufacturer based on city and highway fuel economy test results and vehicle sales. Based on the information generated under the CAFE program, the USDOT is authorized to assess penalties for noncompliance.

National Energy Act

The National Energy Act of 1978 included the following statues: Energy Tax Act, National Energy Conservation Policy Act, Power Plant and Industrial Fuel Use Act, and the National Gas Policy Act. The Power Plant and Industrial Fuel Use Act restricted the fuel used in power plants, however, these restrictions were lifted in 1987. The Energy Tax Act was superseded by the Energy Policy Acts of 1992 and 2005. The National Gas Policy Act gave the Federal Energy Regulatory Commission authority over natural gas production and established pricing guidelines. The National Energy Conservation Policy Act (NECPA) set minimum energy performance standards, which replaced those in the EPCA. The federal standards preempted state standards. The NECPA was amended by the Energy Policy and Conservation Act Amendments of 1985.

Public Utility Regulatory Policies Act of 1978 (Public Law 95-617)

The Public Utility Regulatory Policies Act of 1978 (PURPA) was passed in response to the unstable energy climate of the late 1970s. PURPA sought to promote conservation of electric energy. Additionally, PURPA created a new class of nonutility generators, small power producers, from which, along with qualified co-generators, utilities are required to buy power.

PURPA was in part intended to augment electric utility generation with more efficiently produced electricity and to provide equitable rates to electric consumers. Utility companies are required to buy all electricity from qualifying facilities (Qfs) at avoided cost (avoided costs are the incremental savings associated with not having to produce additional units of electricity). PURPA expanded participation of nonutility generators in the electricity market and demonstrated that electricity from nonutility generators could successfully be integrated with a utility's own supply. PURPA requires utilities to buy whatever power is produced by Qfs (usually cogeneration or renewable energy). The Fuel Use Act (FUA) of 1978 (repealed in 1987) also helped Qfs become established. Under the FUA, utilities were not allowed to use natural gas to fuel new generating technologies, but Qfs, which were by definition not utilities, were able to take advantage of abundant natural gas and abundant new technologies (such as combined-cycle).

Energy Policy Act of 1992

The Energy Policy Act of 1992 is comprised of twenty-seven titles. It addressed clean energy use and overall national energy efficiency to reduce dependence on foreign energy, incentives for clean, radioactive waste protection standards, and renewable energy and energy conservation in buildings and efficiency standards for appliances.

Energy Policy Act of 2005

The Energy Policy Act of 2005 addresses energy efficiency; renewable energy requirements; oil, natural gas and coal; alternative-fuel use; tribal energy, nuclear security; vehicles and vehicle fuels, hydropower and geothermal energy, and climate change technology. The Act provides revised annual energy reduction goals (two percent per year beginning in 2006), revised renewable energy purchase goals, federal procurement of Energy Star or Federal

Energy Management Program-designated products, federal green building standards, and fuel cell vehicle and hydrogen energy system research and demonstration.

Clean Air Act

The Clean Air Act (CAA), §211 (o), as amended by the Energy Policy Act of 2005, requires the Administrator of the U.S. Environmental Protection Agency (USEPA) to annually determine a renewable fuel standard (RFS), which is applicable to refiners, importers, and certain blenders of gasoline, and publish the standard in the FR by November 30 of each year. On the basis of this standard, each obligated party determines the volume of renewable fuel that it must ensure is consumed as motor vehicle fuel. This standard is calculated as a percentage, by dividing the amount of renewable fuel that the CAA requires to be blended into gasoline for a given year by the amount of gasoline expected to be used during that year, including certain adjustments specified by the CAA.

Corporate Average Fuel Economy Program

Compliance with federal fuel economy standards is determined on the basis of each manufacturer's average fuel economy for the portion of their vehicles produced for sale in the U.S. The Corporate Average Fuel Economy (CAFE) program, which is administered by the USEPA, was created to determine vehicle manufacturers' compliance with the fuel economy standards. The USEPA calculates a CAFE value for each manufacturer based on city and highway fuel economy test results and vehicle sales. Based on the information generated under the CAFE program, the USDOT is authorized to assess penalties for noncompliance.

Energy Independence and Security Act of 2007

The Energy Independence and Security Act (EISA) of 2007 was signed into law by President George W. Bush on December 19, 2007. The Acts objectives are to move the United States toward greater energy independence and security, increase the production of clean renewable fuels, protect consumers, increase the efficiency of products, buildings and vehicles, promote greenhouse gas research, improve the energy efficiency of the Federal government, and improve vehicle fuel economy.

The renewable fuel standard in EISA requires 36 billion gallons of ethanol per year by 2022, with corn-based ethanol limited to 15 billion gallons. The new CAFE standard for light duty vehicles is 35 miles per gallon by 2020. EISA also specifies that vehicle attribute-based standards are to be developed separately for cars and light trucks. EISA creates a CAFE credit and transfer program among manufacturers and across a manufacturer's fleet. It would allow an extension through 2019 of the CAFE credits specified under the Alternative Motor Fuels Act. It establishes appliance energy efficiency standards for boilers, dehumidifiers, dishwashers, clothes washers, external power supplies, commercial walk-in coolers and freezers, federal buildings; lighting energy efficiency standards for general service incandescent lighting in 2012; and standards for industrial electric motor efficiency.

3.3.1.2 State Regulations

The CEC and CPUC have jurisdiction over the investor-owned utilities (IOUs) in California. Within the district, the CEC also collects information for the Los Angeles Department of Water and Power (LADWP) and the Burbank, Glendale and Pasadena Municipal Utilities. The applicable state regulations, laws, and executive orders relevant to energy use are discussed below.

<u>California Building Energy Efficiency Standards</u>

California established statewide building energy efficiency standards in CCR, Title 24 - California Building Standards Code in response to a legislative mandate to reduce California's energy consumption. Title 24 contains the regulations that govern the construction of buildings in California. The legislation required the standards to be cost-effective based on the building life cycle and to include both prescriptive and performance-based approaches. The standards are updated approximately every three years by the CEC to allow consideration and possible incorporation of new energy efficiency technologies and methods. The 2005 Building Energy Efficiency Standards were first adopted in November 2003, and took effect October 1, 2005. Subsequently the standards have undergone two updates, one in 2008 and one in 2013. The 2013 Building Energy Efficiency Standards will go into effect on July 1, 2014.

<u>AB 1007 - Alternative Fuels Plan</u>

AB 1007 (Pavley, Chapter 371, Statutes of 2005) requires the CEC to prepare an Alternative Fuels Plan for the state to increase the use of alternative fuels in California. The CEC prepared the plan in partnership with CARB, and in consultation with other state, federal and local agencies in December 2007. The Alternative Fuels Plan assessed various alternative fuels and developed fuel portfolios to meet California's goals to reduce petroleum consumption, increase alternative fuels use, reduce GHG emissions, and increase in-state production of biofuels without causing a significant degradation of public health and environmental quality.

<u>AB 1493 - Vehicle Climate Change Standards</u>

AB 1493 required California to develop and adopt regulations that achieve the maximum feasible and cost-effective reduction of climate change emissions emitted by passenger vehicles and light-duty trucks. Regulations that were designed to improve fuel efficiency were adopted by CARB in September 2004.

<u>SB 1368 - Emission Performance Standards</u>

On September 29, 2006, Governor Schwarzenegger signed into law SB 1368 – Emissions Performance Standards (Perata, Chapter 598, Statutes of 2006). SB 1368 limits long-term investments in baseload generation by California's utilities to power plants that meet an emissions performance standard (EPS) jointly established by the CEC and the CPUC. SB 1368 establishes a standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lbs CO2 per MWh to encourage the development of power plants that meet California's growing energy needs while minimizing their emissions of greenhouse gases.

California Solar Initiative

On January 12, 2006, the CPUC approved the California Solar Initiative (CSI), which provides $2.9 billion in incentives between 2007 and 2017. CSI is part of the Go Solar California campaign, and builds on 10 years of state solar rebates offered to California's IOU territories: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The CSI is overseen by the CPUC, and includes a $2.5 billion program for commercial and existing residential customers, funded through revenues and collected from gas and electric utility distribution rates. Furthermore, the CEC will manage $350 million targeted for new residential building construction, utilizing funds already allocated to the CEC to foster renewable projects between 2007 and 2011.

Current incentives provide an upfront, capacity-based payment for a new system. In its August 24, 2006 decision, the CPUC shifted the program from volume-based to performance-based incentives and clarified many elements of the program's design and administration. These changes were enacted in 2007, when the CSI incentive system changed to performance-based payments.

Reducing California's Petroleum Dependence

The CEC and CARB produced a joint report "Reducing California's Petroleum Dependence" to highlight petroleum consumption and to establish a performance based goal to reduce petroleum consumption in California over the next thirty years. The report includes the following recommendations to the Governor and Legislature regarding petroleum:

- Adopt the recommended statewide goal of reducing demand for on-road gasoline and diesel to 15 percent below the 2003 demand level by 2020 and maintaining that level for the foreseeable future.
- Work with the California delegation and other states to establish national fuel economy standards that double the fuel efficiency of new cars, light trucks, and sport utility vehicles.
- Establish a goal to increase the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020, and 30 percent by 2030.

The CEC will use these recommendations when developing its series of recommendations to the Governor and Legislature for the integrated energy plan for electricity, natural gas, and transportation fuels.

Renewables Portfolio Standard

California's renewables portfolio standard (RPS) requires retail sellers of electricity to increase their procurement of eligible renewable energy resources by at least one percent per year so that 20 percent of their retail sales are procured from eligible renewable energy resources by 2017. If a seller falls short in a given year, they must procure more renewables in succeeding years to make up the shortfall. Once a retail seller reaches 20 percent, they need not increase their procurement in succeeding years. RPS was enacted via SB 1078 (Sher), signed in September 2002 by Governor Davis. The CEC and the CPUC are jointly implementing the standard. In 2006, RPS was modified by SB 107 to require retail sellers of electricity to reach the 20 percent renewables goal by 2010. In 2011, RPS was further modified by SB 2 to require retailers to reach 33 percent renewable energy by 2020.

California Environmental Quality Act (CEQA)

Appendix F of the CEQA Guidelines describes the types of information and analyses related to energy conservation that are to be included in EIRs (or equivalent documents) that are prepared pursuant to CEQA. Energy conservation is described in Appendix F of CEQA Guidelines in terms of decreased per capita energy consumption, decreased reliance on natural gas and oil, and increased reliance on renewable energy sources. To assure that energy implications are considered in project decisions, EIRs (or equivalent documents) must include a discussion of the potentially significant energy impacts of proposed projects, with particular emphasis on avoiding or reducing inefficient, wasteful and unnecessary consumption of energy.

3.3.1.3 Local Regulations

Clean Cities Program

The USDOE Clean Cities Program promotes voluntary, locally based government/industry partnerships for the purpose of expanding the use of alternatives to gasoline and diesel fuel by accelerating the deployment of alternative fuel vehicles and building a local alternative fuel vehicle refueling infrastructure. The mission of the Clean Cities Program is to advance the nation's energy security by supporting local decisions to adopt practices that contribute to the reduction of petroleum consumption. Clean Cities carries out this mission through a network of more than 80 volunteer coalitions, which develop public/private partnerships to promote alternative fuels and vehicles, fuel blends, fuel economy, hybrid vehicles, and idle reduction.

San Gabriel Valley Energy Efficiency Partnership

In April 2006, the SCAG's Regional Council authorized SCAG's Executive Director to enter into a partnership with SCE to incentivize energy efficiency programs in the San Gabriel Valley Subregion. The San Gabriel Valley Energy Wise Program (SGVEWP) agreement was fully executed on October 20, 2006 with the main goal to save a combined three million kilowatt-hours (kWh) by providing technical assistance and incentive packages to cities by 2008. The program has been extended seeks to reduce energy usage in the region by approximately five million kWh by 2012. The SGVEWP is funded by California utility customers and administered by SCE under the auspices of the CPUC.

3.3.2 Energy Trends In General (Statewide)

Figure 3.3-1 shows California's major sources of energy. In 2010, 71 percent of the electricity came from in-state sources, while 29 percent was imported into the state. In 2012, the electricity generated in-state totaled 199,101 gigawatt hours (GWh)[1] while imported electricity totaled 102,866 GWh, with 39,470 GWh coming from the Pacific Northwest, and 63,396 GWh coming from the Southwest (CEC, 2013e)[2]. For natural gas in 2012, 35 percent came from the Southwest, 16 percent came from Canada, nine percent came from in-state, and 40 percent came from the Rocky Mountains (CEC, 2013c)[3]. Also in 2013, 37 percent of the crude oil came from in-state, with 12 percent coming from Alaska, and 51 percent being supplied by foreign sources (CEC, 2011a)[4].

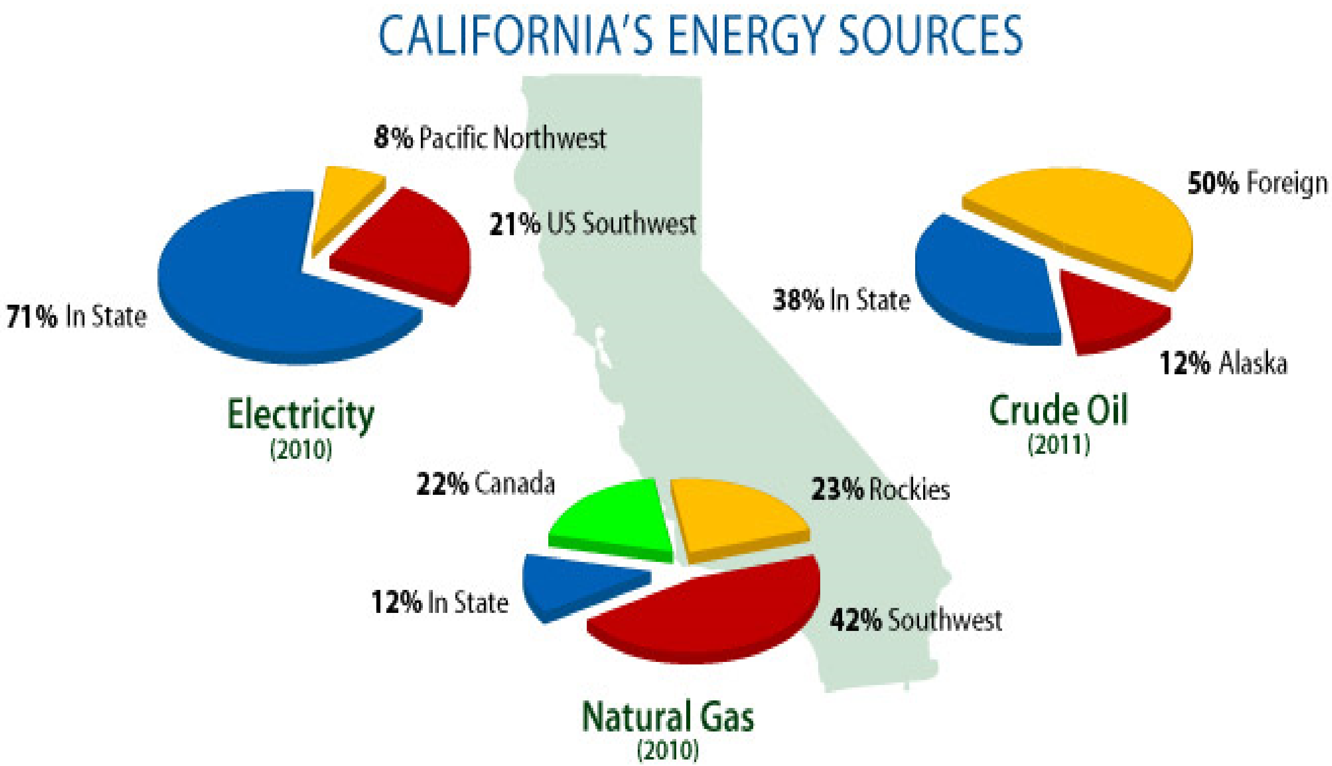

FIGURE 3.3-1
California's Major Sources of Energy[5]

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[1] One gigawatt is equal to one million kilowatts.

[2] Total Electricity System Power, Total System Power for 2013: Changes From 2012; CEC Energy Almanac. http://energyalmanac.ca.gov/electricity/total_system_power.html

[3] Natural Gas Supply By Region, CEC Energy Almanac. http://energyalmanac.ca.gov/naturalgas/natural_gas_supply.html.

[4] Oil Supply Sources to California Refineries, CEC Energy Almanac http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.

[5] California's Major Sources of Energy, CEC Energy Almanac, last updated April 7, 2011. http://energyalmanac.ca.gov/overview/energy_sources.html.

3.3.2.1 Electricity

Power plants in California provided approximately 66 percent of the total in-state electricity demand in 2012 of which 17 percent came from renewable sources such as biomass, geothermal, small hydro, solar, and wind. The Pacific Northwest provided another 13 percent of the total electricity demand of which 24 percent came from renewable sources. The Southwest provided 21 percent of the total electricity demand, with five percent coming from renewable sources. In total, 15.4 percent of the total in-state electricity demand for 2012 came from renewable sources (CEC, 2013e).

Four of the state's largest power plants are located in Basin (CEC, 2014e)[6]. The largest power plants in California are located in northern California: the Moss Landing Natural Gas Power Plant (2,484 megawatts (MW)) is located in Monterey Bay in Monterey County and the Diablo Canyon Nuclear Plant (2,323 MW) is located in Avila Beach in San Luis Obispo County. The third and fourth largest power plants in California are located inside the Basin: the AES Alamitos Natural Gas Power Generating Station (1,970 MW) in Long Beach in Los Angeles County and Haynes Natural Gas Power Plant (net summer capacity 1,724 MW) in Long Beach. The fifth and sixth largest power plants in California are located outside of the Basin: the Ormond Beach Natural Gas Power Plant (1,613 MW) in City of Oxnard within Ventura County and Pittsburg Natural Gas Power Plant (1,370 MW) in the City of Pittsburg within Contra Costa County. The LADWP operates the state's seventh and eighth largest power plants: the AES Redondo Beach Natural Gas Power Plant (1,343 MW) in Redondo Beach and the Castaic Pump-Storage Power Plant[7] in Castaic (1,331 MW). The ninth and tenth largest power plants in California are also located outside of the Basin: the Helms Pumped Storage Facility (1,212 MW) in Sierra National Forest of Fresno County and La Paloma Generating Project (1,200 MW) in West Elk Hills within Kern County.

Local electricity distribution service is provided to customers within southern California by one of two investor-owned utilities – either SCE or SDG&E – or by a publicly owned utility, such as the LADWP and the Imperial Irrigation District. The SCE is the largest electric utility company in Southern California with a service area that covers all or nearly all of Orange, San Bernardino, and Ventura Counties, and most of Los Angeles and Riverside Counties. The SCE delivers 78 percent of the retail electricity sales to residents and businesses in southern California. The SDG&E provides local distribution service to the southern portion of Orange County (SCAG, 2012)[8].

The LADWP is the largest of the publicly owned electric utilities in southern California. The LADWP provides electricity service to the most of the customers located in the City of Los Angeles and provides approximately 20 percent of the total electricity demand in the Basin. The other publicly owned utilities in southern California include Anaheim, Azusa,

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6 California Power Plant Database; CEC; accessed August 2014. http://energyalmanac.ca.gov/powerplants/Power_Plants.xlsx

7 The Castaic Pump-Storage Power plant is operated by the LADWP in cooperation with the Department of Water Resources (DWR).

8 Draft Program Environmental Impact Report for the 2012 – 2035 RTP/SCS; SCAG; December 2011. http://rtpscs.scag.ca.gov/Pages/Draft-2012-PEIR.aspx

Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside, Vernon, and the Imperial Irrigation District (SCAG, 2012).

Table 3.3-1 shows the amount of electricity delivered to residential and nonresidential entities in the counties in the Basin.

TABLE 3.3-1

2013 Electricity Use in GWh (Aggregated, includes self generation and renewables)

Sector	Los Angeles	Orange	Riverside	San Bernardino	Total
Ag & Water Pump	3,113	278	640	513	4,545
Commercial	27,468	9,569	5,896	5,098	48,031
Industry	12,510	2,411	1,254	2,945	19,121
Mining	1,475	385	148	214	2,222
Residential	19,456	6,301	6,125	4,227	36,109
Streetlight	309	102	61	70	542
TCU	3,761	975	561	1,056	6,354
Total	68,093	20,022	14,685	14,124	116,923

Source: CEC –email sent by Steven Mac on August 29, 2014.

3.3.2.2 Natural Gas

Four regions supply California with natural gas: California, the Southwest, the Rocky Mountains, and Canada. The Southwest, the Rocky Mountains, and Canada combined supplied 91 percent of all the natural gas consumed in California in 2012. The remainder is produced in California (CEC, 2013c).

Southern California Gas Company (SoCalGas), an investor-owned utility company, provides natural gas service throughout the district, except for the southern portion of Orange County, portions of San Bernardino County, and the City of Long Beach. The Long Beach Gas and Oil Department (LBGOD) is municipally owned and operated by the City of Long Beach, providing gas service to approximately 500,000 residents and businesses in the cities of Long Beach and Signal Hill (LBGOD, 2014)[9]. The SDG&E provides natural gas services to the southern portion of Orange County. In San Bernardino County, Southwest Gas Corporation provides natural gas services to Victorville, Big Bear, Barstow, and Needles (SCAG, 2012).

[9] Welcome to the Long Beach Gas & Oil Department. Long Beach Gas & Oil Department (LBGOD); accessed August 2014. http://admin.longbeach.gov/lbgo/default.asp

In 2012, about 50 percent of the natural gas consumed in California was for electric generation purposes (801,345 million cubic feet) (USEIA, 2012)[10]. Table 3.3-2 provides the estimated use of natural gas in California by residential, commercial and industrial sectors.

TABLE 3.3-2
California Natural Gas Demand 2014
(Million Cubic Feet per Day – MMcf/day)

Sector	Utility	Non-Utility	Total
Residential	1,218	--	1,218
Commercial	505	--	505
Natural Gas Vehicles	43	--	43
Industrial	934	--	934
Electric Generation	2,026	466	2,492
Enhanced Oil Recovery (EOR) Steaming	44	497	541
Wholesale / International + Exchange	235	--	235
Company Use and Unaccounted-for	80	--	80
EOR Cogeneration / Industrial	--	128	128
Total	**5,085**	**1,090**	**6,175**

Totals may not equal sum of components due to independent rounding.
Source: 2014 California Gas Report. http://www.pge.com/pipeline/library/regulatory/downloads/cgr14.pdf

3.3.2.3 Liquid Petroleum Fuels

California relies on oil produced within the state, Alaska, and foreign nations to supply its refineries and produce the petroleum that is used in automobiles and for other purposes. The percentage of oil that is imported from foreign nations has increased dramatically over the past 20 years. For example, in 1991, California imported just four percent of oil from foreign sources (30.7 million barrels out of a total of 683.5 million barrels), and in 2011, California imported 49.9 percent of oil from foreign sources (300 million barrels out of a total of 600.7 million barrels).

As of April 2014, California is currently ranked third among the oil producing states, behind Texas and North Dakota, respectively (USEIA, 2014a)[11]. California also ranked third in the

[10] Table 5.12 - Consumption of Natural Gas for Electricity Generation by State, by Sector, 2012; U.S. Energy Information Administration (USEIA); accessed August 2014. http://www.eia.gov/electricity/annual/html/epa_05_12.html

[11] U.S. States, State Profiles and Energy Estimates, Rankings: Crude Oil Production; May 2014, USEIA, accessed August 2014. http://www.eia.gov/state/rankings/?sid=US&CFID=16318874&CFTOKEN=ae573cdc61654233-EE9BD34F-25B3-1C83-54586F32B366D836&jsessionid=8430a691f97d1894bc33d35305b7d1c231a9#/series/46

nation in refining capacity as of January 2014, with a combined capacity of almost two million barrels per calendar day from its 18 operable refineries (USEIA, 2014b)[12].

California also ranked first in the consumption of petroleum products used by the transportation sector (USEIA, 2012a)[13]. Most gasoline and diesel fuel sold in California for on-road motor vehicles is refined in California to meet state-specific formulations required by CARB. Major petroleum refineries in California are concentrated in three counties: Contra Costa County in northern California, Kern County in central California, and Los Angeles County in southern California. In Los Angeles County, petroleum refineries are located mostly in the southern portion of the county (SCAG, 2012). In fiscal year 2013, 14,443,650,668 gallons of gasoline[14] and 2,637,184,371 gallons of diesel fuel[15] were sold in California (California State Board of Equalization, 2013). The volume of gasoline also includes aviation fuel. In 2012, 14,480 million gallons of gasoline and 1,587 million gallons of diesel were sold by retail facilities throughout California. Retail sales data reported does not include commercial fleets, government entities, private cardlocks (facilities open only to participating companies and not the general public), or rental facilities/equipment yards. The state total and sales by the four counties within SCAQMD's jurisdiction are presented in Table 3.3.-3.

TABLE 3.3-3
Retail Motor Fuel Sales in California by County (CEC, 2012i)[16]
(millions of gallons per year)

Description	California	Los Angeles	Orange	Riverside	San Bernardino
Gasoline [a]	14,486	3,451	1,355	895	878
Diesel [b]	1,587	244	46	107	188

[a] 2012 California Retail Gasoline Sales by County; CEC; http://energyalmanac.ca.gov/gasoline/retail_fuel_outlet_survey/retail_gasoline_sales_by_county.html

[b] 2012 California Retail Diesel Sales by County; CEC; http://energyalmanac.ca.gov/gasoline/retail_fuel_outlet_survey/retail_diesel_sales_by_county.html

3.3.3 Alternative Clean Transportation Fuels

The demand for transportation fuels in California is increasing at a rapid rate and is projected to grow by almost 35 percent over the next 20 years. Unless habits change, petroleum will be the

[12] California State Profile and Energy Estimates, Quick Facts; USEIA; accessed August 2014. http://www.eia.gov/state/?sid=CA&CFID=16957926&CFTOKEN=f27a8712ad923a0a-6D522B58-237D-DA68-24E25846F72A3365&jsessionid=84301d78ae226ef8ee07326b113a3b1a7331

[13] Table F15: Total Petroleum Consumption Estimates, 2012; USEIA; accessed August 2014. http://www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_fuel/html/fuel_use_pa.html&sid=US&sid=CA

[14] Taxable Gasoline Gallons 10 Year Report; 2013 data; California State Board of Equalization; Fuel Taxes Statistics & Reports, Motor Vehicle Fuel; accessed August 2014. http://www.boe.ca.gov/sptaxprog/reports/MVF_10_Year_Report.pdf

[15] Taxable Diesel Gallons 10 Year Report; 2013 data; California State Board of Equalization; Fuel Taxes Statistics & Reports, Motor Vehicle Fuel; accessed August 2014. http://www.boe.ca.gov/sptaxprog/reports/Diesel_10_Year_Report.pdf

[16] Retail Fuel Report and Data for California; CEC; accessed August 2014. http://energyalmanac.ca.gov/gasoline/piira_retail_survey.html

primary source of California's transportation fuels for the foreseeable future. As demand continues to rise and in-state and Alaskan petroleum supplies diminish, California will rely more and more on foreign imports of crude oil (Consumer Energy Center, 2012)[17].

Alternative fuels, as defined by the Energy Policy Act of 1992, include ethanol, natural gas, propane, hydrogen, biodiesel, electricity, methanol, and P-Series fuels, a family of renewable, non-petroleum liquid fuels that can substitute for gasoline. These fuels are being used worldwide in a variety of vehicle applications. Use of these fuels for transportation can generally reduce air pollutant emissions and can be domestically produced and, in some cases, derived from renewable sources. The Energy Policy Act of 2005 directed the USDOE to carry out a study to plan for the transition from petroleum to hydrogen in a significant percentage of vehicles sold by 2020.

Use of renewable and other alternative fuels in the United States and California is expected to continue growing, primarily as a consequence of federal and state regulations mandating ever-increasing levels of renewable content in gasoline and diesel fuel, carbon reduction rules, and incentives for increasing alternative fuel consumption.

3.3.3.1 Biodiesel

Biodiesel is a domestically produced, renewable fuel that can be manufactured from vegetable oils, animal fats, or recycled restaurant greases. According to the USDOE, pure biodiesel (B100) is considered an alternative fuel under Energy Policy Act. Lower-level biodiesel blends are not considered alternative fuels, but covered fleets can earn one Energy Policy Act credit for every 450 gallons of B100 purchased for use in blends of 20 percent or higher (SCAG, 2012).

Biodiesel is the only alternative fuel to have fully completed the health effects testing requirements under the Clean Air Act (CCA). The use of biodiesel in a conventional diesel engine results in substantial reductions of unburned hydrocarbons, carbon monoxide, and particulate matter compared to emissions from diesel fuel (Consumer Energy Center, 2012a)[18].

Production of biodiesel in the United States dramatically increased in response to federal legislation that went into effect in 2005 included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel, but declined in 2009 and 2010 with the temporary loss of the subsidy in conjunction with poor production economics (high feedstock costs relative to market price of diesel fuel). Output has rebounded as refiners and other obligated parties strive to meet biodiesel blending requirements mandated by the RFS. According to the CEC, at least a sixfold increase in biodiesel production to 188 million

[17] Consumer Energy Center, 2012. Alternative Fuel Vehicles, June 2012. http://www.consumerenergycenter.org/transportation/afvs/

[18] Consumer Energy Center, 2012a. Biodiesel as a Transportation Fuel. http://www.consumerenergycenter.org/transportation/afvs/biodiesel.html

gallons per year and renewable diesel production and delivery to more than 300 million gallons per year in California by 2020 (CEC, 2013)[19].

Biodiesel use in California gradually increasing over the past few years in California, but there is a potential constraint in securing enough low-carbon intensity feedstock to produce biodiesel and renewable diesel. The bulk of the renewable diesel is produced in Singapore and shipped to California (CEC, 2013). As such, biodiesel use in California is estimated to have been nearly 136 million gallons in 2013. Table 3.3-4 shows the reported retail sale of biodiesel was 1,673,555 gallons in 2010 (CEC, 2014h)[20]. Retail sales do not include distributed by commercial fleets, government entities, private cardlocks (unattended dispensing facilities not open to the public), rental facilities/equipment yards, and special user groups. The combination of RFS requirements for obligated parties, substantial renewable identification number (RIN) credit values, availability of sufficient biofuel resources, and California's LCFS will compel development of low-carbon biofuel projects in the state and shift of low-carbon biofuels to California (CEC, 2013).

TABLE 3.3-4
Reported Retail Biodiesel Sales in California in 2010
(gallons per year)

Reporting Year	**Conventional Fuel Component** (gallons)	**Biodiesel Component** (gallons)	**Total Biodiesel Throughput** (gallons)	**Stations Reported**
2010	926,043	747,512	1,673,555	44

Source: CEC, 2014h

3.3.3.2 Natural Gas

Natural gas is a mixture of hydrocarbons comprised mainly of methane (CH4) and is produced either from gas wells or in conjunction with crude oil production worldwide and locally at relatively low cost. The interest in natural gas as an alternative fuel for automobiles stems mainly from its clean burning qualities, its domestic resource base, and its commercial availability to end users. Because of the gaseous nature of this fuel, it must be stored onboard a vehicle in either a compressed gaseous state as compressed natural gas (CNG) or in a liquefied state as liquefied natural gas (LNG) (SCAG, 2012).

Natural gas vehicles have been introduced in a wide variety of commercial applications, from light-duty trucks and sedans (e.g., taxi cabs), to heavy-duty vehicles (e.g., transit buses, street sweepers, and school buses). In California, transit agency buses are some of the most visible CNG vehicles.

[19] 2013 Integrated Energy Policy Report. Transportation Energy Trends. CEC, 2013. http://www.energy.ca.gov/2013_energypolicy/

[20] Retail Biodiesel and E-85 Sales, CEC, Energy Almanac, accessed August 2014. http://energyalmanac.ca.gov/gasoline/retail_fuel_outlet_survey/retail_biodiesel+e85_sales.html

With consumption of natural gas vehicles increasing by 26 percent nationwide and 35 percent in California from 2008 to 2013 (U.S. EIA, 2013)[21], and the probability of a sixfold increase in natural gas vehic~~v~~les and natural gas consumption from 2012 levels by 2020, the fueling infrastructure for natural gas vehicles continues to grow (CEC, 2013). California currently has 281 compressed and 45 liquid natural gas fueling stations. In southern California alone, there are more than 230 natural gas fueling stations in major metropolitan areas from Los Angeles to the Mexican border (USDOE, 2012)[22] .

3.3.3.3 Electricity

Electricity can be used as a transportation fuel to power battery electric and fuel cell vehicles. When used to power electric vehicles (EVs), electricity is stored in an energy storage device such as a battery. Fuel cell vehicles use electricity produced from an electrochemical reaction that takes place when hydrogen and oxygen are combined in the fuel cell "stack." The production of electricity using fuel cells takes place without combustion or pollution and leaves only two byproducts, heat and water.

Electric vehicles have several different charging systems: 120-volt, 240-volt, direct-current, and inductive charging. An electric vehicle that accepts 120-volt power can do so from any standard electrical outlet with a 12- or 16-amp dedicated branch circuit (with no other receptacles or loads on the circuit). A 240-volt system requires the installation of a home charging station and is available at most public charging stations. Direct current (DC) fast charging equipment (480 volt) provides 50 kW to the battery. This option enables charging along heavy traffic corridors and at public stations. Inductive charging equipment was installed for all electric vehicles in the early 1990s, such as the GM/Saturn EV-1, Toyota RAV4 EV, and the Chevy S10, and is still being used in certain areas. Some companies are working on inductive charging options for future electric drive vehicles. The most common types of EVs use either 120-volt or 240-volt electrical systems (SCAG, 2012).

The USDOE's Advanced Vehicle Testing Activity (AVTA) promotes the use of EVs in commercial fleets in the United States. During 1996, AVTA requested and received proposals from interested groups to become qualified vehicle testers (QVT). SCE headed one QVT. According to SCE, California's approximately 20,000 megawatts of excess off-peak (nighttime) electricity capacity would allow the charging of millions of electro-drive technologies without the need for new power generation facilities (SCAG, 2012).

As of mid-2013, 32,000 plug-in electric vehicles (PEVs) and an additional 14,000 neighborhood electric vehicles are on the roads. More than 8,000 electric vehicle charge points have been funded by the CEC and the air quality management districts in California. The Governor's ZEV Executive Order[23] and CARB's ZEV mandate, combined with a federal tax credit and incentives for electric vehicle rebates and electric charger installations, are advancing the electric vehicle market penetration in California (CEC, 2013).

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21 Natural Gas Consumption by End Use, U.S.EIA 2014. http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

22 Alternative Fueling Station Locator, U.S. DOE, 2014. http://www.afdc.energy.gov/afdc/locator/stations/state

23 The Executive Order calls for California to ensure infrastructure is developed to support one million zero-emission vehicles by 2020 and 1.5 million by 2025.

One of the attractions of PEVs compared to internal combustion engine vehicles is the convenience of home charging instead of fueling at a gas station. ICF International estimates that in the early market, roughly 95 percent of charging will either be at home or at fleet facilities. Charging at home may require additional equipment and the broad consensus is that residential charging is the highest priority for deployment because consumers like the convenience and it encourages charging during periods of off-peak electrical demand. The CEC will consider providing PEV consumers with incentives to help defray the cost of home electric vehicle supply equipment (EVSE) (CEC, 2011)[24].

3.3.3.4 Ethanol and E85

Ethanol, or ethyl alcohol, is a clear, colorless liquid that is the same alcohol that is found in alcoholic beverages. In California, ethanol is blended into gasoline up to 10 percent for use by most automobiles. Ethanol is also be used in a more pure state as an alternative fuel when the blend is 85 percent ethanol and 15 percent gasoline (E85).

Most ethanol used for fuel in California is being blended into gasoline at concentrations from five to ten percent, and has replaced methyl tertiary butyl ether (MTBE) as a gasoline component. Most gasoline supplied in the state today contains at least six percent ethanol (Consumer Energy Center, 2012b)[25].

Blends of at least 85 percent ethanol are considered alternative fuels under the Energy Policy Act. E85, a blend of 85 percent ethanol and 15 percent gasoline is used in flexible fuel vehicles (FFVs) that are currently offered by most major auto manufacturers. FFVs can run on gasoline, E85, or any combination of the two and qualify as alternative fuel vehicles under Energy Policy Act regulations (SCAG, 2012).

In the United States, ethanol is most widely produced through fermentation and distillation of corn. As of January 1, 2013, the U.S. fuel ethanol production capacity is reported as nearly 14 billion gallons per year. Since 2009, three of the five existing ethanol facilities in California have begun regular operations. Of the two remaining, one has been shut down and dismantled, and the other is operating intermittently. California uses roughly 1.5 billion gallons of ethanol per year, of which nearly 175 million gallons per year are produced in California and the remainder is imported corn ethanol from the Midwest and foreign sources (CEC, 2013).

As of 2013, there are about 500,000 FFVs operating in California. Although there is a large population of FFVs in California, there are a modest but growing number of retail stations that offer E85. As of 2009, there were approximately 83 stations that offered E85 to the public. According to the CEC, California nearly sold 6.5 million gallons of E85 in 2012 (CEC, 2013). As of July 2011, there were approximately 60 stations that offered E85 to the public. Table 3.3-5 shows the reported retail sale of E85 was 1,995,812 gallons in 2010 (CEC, 2014h). Retail sales do not include E85 that is distributed by commercial fleets,

[24] Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report, August 2011. http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf

[25] Ethanol as a Transportation Fuel, Consumer Energy Center, 2014. http://www.consumerenergycenter.org/transportation/afvs/ethanol.html

government entities, private cardlocks (unattended dispensing facilities not open to the public), rental facilities/equipment yards, and special user groups. With upgraded infrastructure and increasing availability of E85, sales in California are forecast to rise from 13.2 million gallons in 2009 to more than three billion gallons by 2030 (CEC, 2011).

TABLE 3.3-5
Reported Retail E85 Sales in California in 2010
(gallons per year)

Conventional Fuel Component)	Ethanol Component	Total E85 Throughput	Count of Facilities
299,372	1,696,440	1,995,812	36

Source: CEC, 2012h

During 2010, rail imports represented 95.8 percent of the ethanol consumed and in-state production represented 4.2 percent. There were no marine imports of ethanol during 2010 due to unfavorable economics in foreign source countries. However, ethanol imports from Brazil are projected to displace from 250 million to 400 million gallons per year of corn-based ethanol imports because Brazilian sugarcane ethanol is the largest near-term contributor that can achieve the standards mandated by the RFS and LCFS because of its lower carbon intensity value when compared to corn-based ethanol (CEC, 2011).

3.3.3.5 Methanol and M85

Methanol, also known as wood alcohol, can be used as an alternative fuel in flexible fuel vehicles that run on M85 (a blend of 85 percent methanol and 15 percent gasoline). Methanol was sold in California as part of a public-private partnership demonstration program between the state of California and oil companies. After the demonstration program ended, however, the oil companies discontinued selling M85. M85 is no longer available.

3.3.3.6 Hydrogen as a Transportation Fuel

Hydrogen is the simplest and lightest fuel. At atmospheric pressure and ambient temperatures hydrogen is a colorless, odorless, tasteless, and non-toxic gas that burns invisibly. Hydrogen is being explored for use in combustion engines and fuel cell electric vehicles. The ability to create hydrogen from a variety of resources and its clean-burning properties make it a desirable alternative fuel.

In 2011, there were approximately 250 hydrogen fuel cell vehicles (FCVs) operating in California, compared to only 15 registered in 2009. These vehicles use stored hydrogen, which is combined with oxygen from the atmosphere through an electrochemical reaction to produce electricity, which is then used to power an electric motor. Like battery electric vehicles, FCVs produce no tailpipe emissions and store the hydrogen fuel in on-board pressure tanks. Today's FCVs hold enough hydrogen in their on-board tanks to support driving ranges of roughly 250 miles. Current refueling is relatively quick, taking about three to five minutes per fill for a 700 bar tank (CEC, 2011).

As of August 2014, California has 10 public hydrogen fueling stations, 11 private hydrogen fueling stations, and 46 hydrogen fueling stations in development (USDOE, 2014). Without a substantial transportation distribution system in place for hydrogen transportation use, hydrogen could be transported and delivered using the established hydrogen infrastructure. However, for significant market penetration, the infrastructure will need further development (SCAG, 2012).

3.3.3.7 Propane

Propane (C3H8) is a three-carbon alkane gas used as a clean-burning, high-energy alternative fuel for decades to power light-, medium-, and heavy-duty propane vehicles. Propane, also known as liquefied petroleum gas (LPG) or autogas, is produced as a by-product of natural gas processing and petroleum refining. As an alternative fuel, it is stored under pressure inside a tank, as a colorless, odorless liquid and as pressure is released, the liquid propane vaporizes and turns into gas that is used for combustion. Propane has a high octane rating and excellent properties for spark-ignited internal combustion engines. It is non-toxic and presents no threat to soil, surface water, or groundwater.

Propane is a popular fuel choice for vehicles because there is already an infrastructure of pipelines, processing facilities, and storage for its efficient distribution. Domestic availability, high-energy density, clean-burning qualities, and its relatively low cost also add to its popularity.

Propane is the third most commonly used transportation fuel used in the United States, behind gasoline and diesel. Over time, propane has been used in several niche applications such as for fork-lifts, both inside and outside warehouses, and at construction sites. Use of propane can result in lower vehicle maintenance costs, lower emissions, and fuel costs savings when compared to conventional gasoline and diesel. In California, the state-wide fleet operated around 13.37 million vehicles that use propane as an alternative fuel (US EIA, 2014)[26]. According to the CEC's survey of retail fuel stations and sales, 805 retail fuel stations sold 25.44 million gallons of propane in 2012 (CEC, 2014i)[27].

3.3.4 Renewable Energy

Renewable energy is energy that comes from sources that regenerate and can be sustained indefinitely, unlike fossil fuels, which are exhaustible. The five most common renewable sources are biomass, hydropower, geothermal, wind, and solar. Unlike fossil fuels, non-biomass renewable sources of energy do not directly emit greenhouse gasses.

The production and use of renewable fuels has grown quickly in recent years as a result of higher prices for oil and natural gas, and a number of state and federal government incentives, including the Energy Policy Acts of 2002 and 2005. The use of renewable fuels is expected to continue to grow over the next 30 years, although projections show that reliance on non-renewable fuels to meet most energy needs will continue.

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26 Alternative Fuel Vehicle Data. http://www.eia.gov/renewable/afv/users.cfm#tabs_charts-5

27 Retail Fuel Report and Data for California. http://energyalmanac.ca.gov/gasoline/piira_retail_survey.html

In 2012, consumption of renewable resources in the United States totaled about nine quadrillion British thermal units (Btu) or about nine percent of all energy used nationally. About 12 percent of U.S. electricity was generated from renewable resources in 2012 (U.S. EIA, 2013a)[28]. In 2012, 20 percent of all electricity came from renewable resources in California (CEC, 2014g)[29].

The RPS requires investor-owned utilities, electric service providers, and community choice aggregators regulated by the CPUC to procure 33 percent of retail sales per year from eligible renewable sources by 2020. CPUC issues quarterly renewable energy progress report to the state Legislature, showing that the state's utilities have met the goal of serving 20 percent of their electricity with renewable energy and are already on track to far surpass that goal in 2012 (CEC, 2014g). The quarterly reports report focuses on California's three large investor-owned utilities: PG&E, SCE, and SDG&E. These investor-owned utilities currently provide approximately 68 percent of the state's electric retail sales and analyzing this data provides significant insight into the state's RPS progress. On April 1, 2014, the large investor owned utilities reported in their 33% RPS Procurement Progress Reports that they served 20.9 percent of their retail electric load with RPS-eligible generations during the first compliance period (CP 1) from 2011 to 2013 (CEC, 2014g). Table 3.3-6 shows the renewable electricity use in Los Angeles, Orange, Riverside and San Bernardino in 2013.

TABLE 3.3-6
2013 Renewable Electricity Use in the District (in GW)

Sector	Los Angeles	Orange	Riverside	San Bernardino	Total
Ag & Water Pump	6	1	4	1	**12**
Commercial	244	63	85	59	**451**
Industry	8	3	1	6	**18**
Mining	12	1	0	0	**14**
Residential	184	71	104	59	**419**
TCU	5	0	4	16	**25**
Total	**459**	**140**	**198**	**141**	**937**

Source: California Energy Commission –email sent by Steven Mac on August 29, 2014.

3.3.4.1 Hydroelectric Power

Hydroelectric power, or hydropower, is generated when hydraulic turbines connected to electrical generators are turned by the force of flowing or falling water. In 2013, hydroelectric-produced electricity used by California totaled nearly 27,176 GWh or 9.15 percent of the total system power. In-state production accounted for around 90 percent of all hydroelectricity, while imports from other states totaled 10 percent (CEC, 2013e).

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28 Renewable Energy Explained. http://www.eia.gov/energyexplained/index.cfm?page=renewable_home
29 Renewables Portfolio Standard: Quarterly Report. http://www.cpuc.ca.gov/NR/rdonlyres/93E7E363-75A6-40C8-997D-705C53A2713D/0/2014Q1RPSReportFINAL.pdf

California has nearly 265[30] hydroelectric facilities with an installed capacity of approximately 13,882 MW[31]. Hydro facilities are divided into two categories with larger than 30 MW capacity facilities (e.g., "large hydro") and smaller than 30 MW capacity facilities (e.g., "small hydro") that are totaled into the renewable energy portfolio standards. The amount of hydroelectricity produced varies each year, largely dependent on rainfall. During the drought from 1986 to 1992, production fell to less than 22,400 GWh (CEC, 2014f)[32], while total generation increased from 211,028 GWh to 245,535 GWh over the same period of time.

The larger hydro plants located on dams in California (such as Shasta, Folsom, Oroville, etc.) are operated by the U.S. Bureau of Reclamation and the DWR. Small hydro plants are operated by utilities, mainly PG&E and Sacramento Municipal Utility District. The licensing of hydro plants is done by the Federal Energy Regulatory Commission with input from state and federal energy, environmental protection, fish and wildlife, and water quality agencies.

3.3.4.2 Geothermal Energy

Geothermal energy technologies use the clean, sustainable heat from the earth. Geothermal resources include the heat retained in shallow ground, hot water and rock found a few miles beneath the Earth's surface, and extremely high-temperature molten rock, also known as magma, located deep in the Earth. Geothermal energy can be used to generate electricity or used directly in many commercial and industrial applications.

The energy from high-temperature reservoirs (e.g., from 225 degrees Fahrenheit (°F) to 600 °F) can be used by three different types of geothermal power plants to produce electricity. Dry steam plants use steam from underground wells to rotate a turbine which activates a generator to produce electricity. Binary cycle plants use the heat from lower-temperature reservoirs (e.g., from 225 °F to 360 °F) to boil a working fluid, which is then vaporized in a heat exchanger and used to power a generator. The water, which never comes into direct contact with the working fluid, is then injected back into the ground to be reheated. The flash stream plant, the most common type of geothermal power plant, uses water at temperatures above 360 °F. As hot water flows up through wells in the ground, the decrease in pressure causes some of the water to boil into steam which is then used to power a generator (USDOE, 2014a)[33].

The most developed of the high-temperature resource areas of the state is the Geysers. North of San Francisco, the Geysers were first tapped as a geothermal resource to generate electricity in 1960. It is one of only two locations in the world where a high-temperature, dry steam is found that can be directly used to turn turbines and generate electricity. Dry

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30 CEC, 2013a. Annual Generation, August 2014. http://energyalmanac.ca.gov/electricity/web_qfer/Annual_Generation.php

31 CEC, 2013b. Electric Generation Capacity & Energy, August 2014. http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

32 Overview of Natural Gas in California, 2014. http://www.energyalmanac.ca.gov/naturalgas/overview.html

33 Energy Basics: Geothermal Electricity Production. http://energy.gov/eere/energybasics/articles/geothermal-technology-basics

steam does not create condensation, which damages steam turbine blades. Other major geothermal locations in the state include the Imperial Valley area east of San Diego and the Coso Hot Springs area near Bakersfield.

Because of its location on the Pacific's "ring of fire" and because of tectonic plate conjunctions, California contains the largest amount of geothermal generating capacity in the United States. In2013, geothermal energy in California produced 12,485GWh of electricity. Combined with another 707 GWh of imported geothermal electricity, the geothermal energy produced 4.44percent of the state's total system power. A total of 43[34]operating geothermal power plants with an installed capacity of 2,703 MW[35] are in California, about two-thirds of the total United States' geothermal generation (CEC, 2014b).

Direct use systems harness the energy from low to moderate temperature reservoirs (e.g., from 68 °F to 302 °F) for various commercial and industrial uses, such as heating buildings, growing plants in greenhouses, drying crops, heating water at fish farms, and pasteurizing milk. Usually, a well is drilled into a geothermal reservoir to provide a steady stream of hot water. The water is brought up through the well, and a mechanical system that utilizes piping, heat exchangers and controls to deliver the heat directly for its intended use. A disposal system then either injects the cooled water underground or disposes of it on the surface (CEC, 2014b)[36].

Forty-six of California's 58 counties have lower temperature resources for direct-use geothermal. In fact, the City of San Bernardino has developed one of the largest geothermal direct-use projects in North America, heating at least three dozen buildings, including a 15-story high-rise and government facilities, with fluids distributed through 15 miles of pipelines (Consumer Energy Center, 2012c)[37].

3.3.4.3 Biomass Electricity

Biomass technologies break down organic matter to release stored energy from the sun. There are many types of biomass - organic matter such as plants, residue from agriculture and forestry, and the organic component of municipal and industrial wastes - that can now be used to produce fuels, chemicals, and power. This flexibility has resulted in the increased use of biomass technologies with 53 percent of all renewable energy consumed in the U.S. in 2007 coming from biomass (USDOE, 2013a)[38].

Biopower is the production of electricity or heat from biomass resources by technologies including direct combustion, co-firing, and anaerobic digestion.

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[34] CEC, 2011b. List of Geothermal Powerplants in California. http://energyalmanac.ca.gov/renewables/

[35] CEC, 2013b. Electric Generation Capacity & Energy. http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

[36] California Geothermal Energy Statistics & Data. http://energyalmanac.ca.gov/renewables/geothermal/index.html

[37] Geothermal Energy. http://www.consumerenergycenter.org/renewables/geothermal/index.html

[38] Biomass Technology Basics. http://energy.gov/eere/energybasics/articles/biomass-technology-basics

Direct Combustion

Direct combustion using conventional boilers is the most common method of producing electricity from biomass. Boilers primarily burn waste wood products from the agriculture and wood-processing industries to produce steam that spins a turbine connected to a generator to produce electricity. Municipal solid waste power plants use direct combustion to create electricity through three methods:

- Mass Burn: Sorted municipal refuse is fed into a hopper to feed a boiler. The heat from the combustion process is used to turn water into steam to power a turbine-generator.

- Refuse-Derived Fuel: Pelletized or fluff municipal refuse, which comes from a by-product of a resource recovery operation where non-combustible materials are removed, are used to feed a boiler. The heat from the combustion process is used to turn water into steam to power a turbine-generator.

- Pyrolysis/Thermal Gasification: Related technologies where thermal decomposition of organic material at elevated temperatures with little (Thermal Gasification) to no (Pyrolysis) oxygen or air produces combustible gases. The gases are combusted to produce heat and turn water into steam to power a turbine-generator.

Co-Firing

Co-firing involves replacing a portion of the petroleum-based fuel in high-efficiency coal-fired boilers with biomass. Co-firing has been successfully demonstrated in most boiler technologies, including pulverized coal, cyclone, fluidized bed, and spreader stoker units. Co-firing biomass can significantly reduce the sulfur dioxide emissions of coal-fired power plants and is a least-cost renewable energy option for many power producers.

Anaerobic Digestion

Anaerobic digestion, or methane recovery, is a common technology used to convert organic waste to electricity or heat. It is widely used in the agriculture, municipal waste, and brewing industries. In anaerobic digestion, organic matter is decomposed by bacteria in the absence of oxygen to produce methane and other byproducts that form a renewable natural gas (USDOE, 2013)[39].

The Los Angeles County Sanitation District (LACSD) operates a combined cycle turbine facility in Carson that uses digester gas to produce 20 MW. In addition, the LACSD operates a landfill gas Rankine cycle steam plant at the Puente Hills Landfill to produce approximately 48 MW.

Lastly, Royal Farms No. 1 in Tulare, California is a third example of anaerobic digestion use. Hog manure is slurried and sent to a Hypalon-covered lagoon for biogas generation. The collected biogas fuels a 70 kW engine-generator and a 100 kW engine-generator which

[39] Anaerobic Digestion Basics. http://energy.gov/eere/energybasics/articles/anaerobic-digestion-basics

helps the farm to be able to meet its own monthly electric and heat energy demand (CEC, 2014j)[40].

There are about 132 waste-to-energy plants in California, with a total capacity of almost 1,000 MW. In 2007, 6,236 GWh of electricity in homes and businesses was produced from biomass: burning forestry, agricultural, and urban biomass; converting methane-rich landfill gas to energy; and, processing wastewater and dairy biogas into useful energy. Biomass power plants produced 2.1 percent of the total electricity in California in 2007, or about one-fifth of all the renewable energy (CEC, 2014j).

3.3.4.4 Wind Power

Wind power is the conversion of the kinetic energy of the wind into a useful form of energy. Wind can be harnessed by wind turbines, windmills, windpumps, or sails. These technologies use wind power for practical purposes such as generating electricity, grinding grain, pumping water, or propelling a boat.

A wind turbine works much like the propeller of an airplane. The blades of a turbine are tilted at an angle and contoured such that the movement of the air is channeled creating low and high pressures on the blade that force it to move. The blade is connected to a shaft, which in turn is connected to an electrical generator. The mechanical energy of the turning blades is changed into electricity.

California has several wind farms, a group of wind turbines in the same location used to produce electricity, strategically placed in windy areas, as one of the problems with using wind to generate power is that wind is not always constant.

Wind energy plays an integral role in California's electricity portfolio. In 2007, turbines in wind farms generated 9.75 GWh[41] of electricity. Additionally, hundreds of homes and farms are using smaller wind turbines to produce electricity (CEC, 2014k)[42].

There are many windy areas in California. Problems with using wind to generate power are that it is not windy all year long nor is the wind speed constant. It is usually windier during the summer months when wind rushes inland from cooler areas, such as near the ocean, to replace hot rising air in California's warm central valleys and deserts. By placing wind turbines in these windy areas, California’s wind power supply variance can be minimized. Utility-scale wind power generation facilities can be found in Altamont Pass, Solano, Pacheco Pass, the Tehachapi Ranges, and San Gorgonio Pass.

3.3.4.5 Solar (Photovoltaic Cells)

Solar energy technologies produce electricity from the energy of the sun through photovoltaic (PV) cells, also known as solar cells. PV cells are electricity-producing devices

[40] Waste to Energy & Biomass in California. http://www.energy.ca.gov/biomass/index.html
[41] U.S. EIA, 2012b. Table 3.17 Net Generation from Wind. http://www.eia.gov/electricity/annual/html/epa_03_17.html
[42] Wind Energy in California. http://www.energy.ca.gov/wind/index.html

made of semiconductor materials coming in many sizes and shapes, often connected together to ultimately form PV systems. When light shines on a PV cell, the energy of absorbed light transfers to electrons in the atoms of the PV cell semiconductor material causing electrons to escape from their normal positions in the atoms and become part of the electric flow, or current, in an electrical circuit. While small PV systems can provide electricity for homes, businesses, and remote power needs, larger PV systems provide much more electricity for contribution to the electric power system.

The PV cells for small systems can be purchased in two formats: 1) as a stand-alone module that is attached to the roof or on a separate system; or, 2) using integrated roofing materials with dual functions as a regular roofing shingle and as a solar cell making electricity.

California's cumulative installed capacity of PV systems in 1998 was 6.3 MW. As of 2013, the capacity of PV systems reached about 3,072 MW[43], producing 5,389 GWh of electricity for the California (CEC, 2013d).

3.3.4.6 Solar Thermal Energy

Solar thermal energy (STE) is the technology for converting the sun's energy into thermal energy (heat) through solar thermal collectors. The U.S. EIA classifies solar thermal collectors into three categories:

- Low-temperature: Flat plate collectors are used to warm homes, buildings, and swimming pools.
- Medium-temperature: Flat plate collectors are used to heat water or air for residential and commercial uses.
- High-temperature: Mirrors or lenses are used to concentrate STE for electric power production.

Low and medium-temperature collectors can be further classified as either passive or active heating systems. In a passive system, air is circulated past a solar heat surface and through the building by convection (meaning that less dense warm air tends to rise while denser cool air moves downward). No mechanical equipment is needed for passive solar heating. Active heating systems require a collector to absorb and collect solar radiation. Fans or pumps are used to circulate the heated air or heat absorbing fluid. Active systems often include some type of energy storage system.

High-temperature systems used in solar thermal power plants use the sun's rays to heat a fluid to very high temperatures through the use of mirrors or lenses. The fluid is then circulated through pipes so it can transfer its heat to water to produce steam. The steam, in turn, is converted into mechanical energy in a turbine and into electricity by a conventional generator coupled to the turbine.

California has 11 of the 13 solar thermal power plants in the United States. These facilities are concentrated in the desert areas of the state in the Mojave area. Solar thermal plants

[43] CEC, 2013b. Electric Generation Capacity & Energy. http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

produced 675 GWh in 2007, or 0.22 percent of the state's total electricity production (CEC, 2014d)[44].

California's electric utility companies are required to use renewable energy to produce 20 percent of their power by 2010 and 33 percent by 2020 and a main source of the required renewable energy will be solar energy. Many large solar energy projects are being proposed in California's desert area on federal Bureau of Land Management (BLM) land. The developments of 34 large solar thermal power plants have been proposed with a planned combined capacity of 24,000 MW (CEC, 2014d).

3.3.5 Consumptive Uses

3.3.5.1 Transportation

Transportation (i.e., the movement of people and goods from place to place) is an important end use of energy in California, accounting for approximately 40 percent of total statewide energy consumption in 2012, and 11 percent of total U.S. energy consumption (U.S. EIA, 2012)[45]. Nonrenewable energy products derived from crude oil, including gasoline, diesel, kerosene, and residual fuel, provide most of the energy consumed for transportation purposes by on-road motor vehicles (e.g., automobiles and trucks), locomotives, aircraft, and ships. In addition, energy is consumed in connection with construction and maintenance of transportation infrastructure, such as highways, rail facilities, runways, and shipping terminals. Trends in transportation-related technology foretell increased use of electricity and natural gas for transportation purposes.

Gasoline is the most-used transportation fuel in California. Within the transportation sector, gasoline is used primarily by light-duty vehicles. In 2010, California consumed gasoline at a rate of 40.7 million gallons per day, or 10.7 percent of the national demand of 379.4 million gallons per day. SCAG is leading a regional effort with the goal of accelerating fleet conversion to near zero and zero-emission transportation technologies. Alternative fuels for transportation include, but are not limited to: biodiesel, electricity, ethanol, hydrogen, natural gas, propane, biobutanol, biogas, hydrogenation-derived renewable diesel (HDRD), methanol, P-Series, and xTL Fuels (Fischer-Tropsch). The Ports, vehicle manufacturers, and other entities are demonstrating new zero-emission truck technologies including battery-electric, fuel-cell, and hybrid-electric trucks with all electric range (AER) (SCAG, 2012a)[46].

3.3.5.2 Residential, Commercial, Industrial, and Other Uses

Major energy consumption sectors (in addition to transportation) include residential, commercial, industrial uses as well as street lighting, mining, and agriculture. Unlike transportation, these sectors primarily consume electricity and natural gas. In 2013, the total annual electricity consumption in the district was approximately 116,947 million kWh (36,109 million kWh for residential uses and 80,838 million kWh for non-residential uses)

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44 California Solar Energy Statistics & Data. http://energyalmanac.ca.gov/renewables/solar/index.html
45 California: State Profile & Estimates. http://www.eia.gov/state/?sid=CA
46 Regional Transportation Plan 2012-2035. http://rtpscs.scag.ca.gov/Documents/2012/final/f2012RTPSCS.pdf

(CEC, 2013). Table 3.3-7 shows the electricity use in Los Angeles, Orange, Riverside and San Bernardino counties in 2013.

TABLE 3.3-7
2013 Electricity Use in the District by County (in millions of kWh)

Sector	Los Angeles	Orange	Riverside	San Bernardino	Total
Residential	19,456	6,301	6,125	4,227	**36,109**
Non-Residential	48,654	13,721	8,566	9,897	**80,838**
Total	**68,110**	**20,022**	**14,691**	**14,124**	**116,947**

Source: CEC, Energy Consumption Data Management System, Energy Consumption by County, 2013. http://www.ecdms.energy.ca.gov/elecbycounty.aspx

Within the residential sector, lighting, small appliances, and refrigeration account for most (approximately 60 percent) of the electricity consumption, and within the industrial and commercial sector, lighting, motors, and air cooling account for most (approximately 65 percent) of the electricity consumption. Electricity use by households varies depending on the local climate and on the housing type (e.g., single-family vs. multi-family), as per the four distinct geographic zones in the SCAG region: the cooler and more temperate coastal zone; an inland valley zone; the California central valley zone, and the desert zone, where temperatures are more extreme.

Based on CEC 2013 Revised High Energy Demand, California consumed approximately 12,767 million therms of natural gas per year in 2013. The SoCal Gas planning area is composed of the SCE, Burbank and Glendale, Pasadena, and LADWP electric planning areas. According to the SoCal Gas Baseline Natural Gas Forecast, approximately 7,357 million therms of natural gas were consumed. The CEC expects residential natural gas use to increase by approximately 1.5 percent per year and commercial natural gas use to increase by approximately3.9 percent per year (CEC, 2014a)[47]. Industrial natural gas demand has also increased such that the most recent data from the CEC show that the residential sector uses the largest amount of natural gas, both across the state and in the SCAG region. Statewide, the industrial sector was second in the amount of natural gas consumed. The commercial sector falls behind residential, mining, and industrial uses in natural gas consumption in the SCAG region and statewide. The agricultural sector accounts for only one percent of the natural gas use statewide and in the SCAG region.

3.3.5.3 Consumption Reduction Efforts

There are various policies and initiatives to reduce petroleum vehicle fuel consumption and increase the share of renewable energy generation and use in the region. These strategies include energy efficient building practices, smarter land use with access to public transportation, increasing automobile fuel efficiency, and participating in energy efficiency incentive program. All publicly-owned utilities and most municipal-owned utilities that provide electric and natural gas service also administer energy conservation programs.

[47] California Energy Demand: 2014-2024. http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC_200-2013-004-SD-V1-REV.pdf

These programs typically include home energy audits; incentives for replacement of existing appliances with new, energy-efficient models; provision of resources to inform businesses on development and operation of energy-efficient buildings; and construction of infrastructure to accommodate increased use of motor vehicles powered by natural gas or electricity (CEC, 2014)[48].

[48] California Energy Consumption Database. http://www.ecdms.energy.ca.gov/

SUBCHAPTER 3.4

HAZARDS AND HAZARDOUS MATERIALS

Hazardous Materials Regulations

Emergency Response to Hazardous Materials and Waste Incidents

Hazardous Materials Incidents

Hazards Associated with Air Pollution Control and Alternative Fuels

3.4 HAZARDS AND HAZARDOUS MATERIALS

Implementation of PR 4001, while intended to improve overall air quality, may have direct or indirect hazards and hazardous materials impacts associated with their implementation. Hazard concerns are related to the potential for fires, explosions or the release of hazardous materials/substances in the event of an accident or upset conditions.

The potential for hazards exist in the production, use, storage, and transportation of hazardous materials. Hazardous materials may be found at industrial production and processing facilities. Some facilities produce hazardous materials as their end product, while others use such materials as an input to their production process. Examples of hazardous materials used as consumer products include gasoline, solvents, and coatings/paints. Hazardous materials are stored at facilities that produce such materials and at facilities where hazardous materials are a part of the production process. Specifically, storage refers to the bulk handling of hazardous materials before and after they are transported to the general geographical area of use. Currently, hazardous materials are transported throughout the district via all modes of transportation including rail, highway, water, air, and pipeline.

The Recirculated NOP/IS identified he following adverse hazards and hazardous materials impacts specific to the implementation of the proposed project: use of alternative fuels in place of conventional fuels could result in increased hazards associated the increased transport; and, use and handling of alternative fuels. Potential exposure to a toxic air contaminant (ammonia) would be associated with installation and operation of control equipment that utilize selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) on industrial combustion sources such as boilers and heaters, as well as large diesel engines on mobile sources to reduce NOx, including off-road diesel engines (e.g., locomotive engines and marine vessel engines).

3.4.1 Hazardous Materials Regulations

Incidents of harm to human health and the environment associated with hazardous materials have created a public awareness of the potential for adverse effects from careless handling and/or use of these substances. As a result, the use, storage and transport of hazardous materials are subject to numerous laws and regulations at all levels of government. The most relevant existing hazardous materials laws and regulations include hazardous materials management planning, hazardous materials transportation, hazardous materials worker safety requirements, hazardous waste handling requirements and emergency response to hazardous materials and waste incidents. Potential risk of upset is a factor in the production, use, storage and transportation of hazardous materials. Risk of upset concerns are related to the risks of explosions or the release of hazardous substances in the event of an accident or upset. The most relevant hazardous materials laws and regulations are summarized in the following subsection of this section.

3.4.1.1 Definitions

A number of properties may cause a substance to be hazardous, including toxicity, ignitability, corrosivity, and reactivity. The term "hazardous material" is defined in different ways for different regulatory programs. For the purposes of this document, the term hazardous material refers to both hazardous materials and hazardous wastes. A hazardous material is defined as hazardous if it appears on a list of hazardous materials prepared by a federal, state, or local regulatory agency or if it has characteristics defined as hazardous by such an agency. Hazardous material is defined in HSC §25501 (k) as follows:

> Hazardous material means any material that because of its quantity, concentrations, or physical or chemical characteristics, poses a significant present or potential hazard to human health and safety or to the environment if released into the workplace or the environment. Hazardous materials include but are not limited to hazardous substances, hazardous waste, and any material which a handler or the administering agency has a reasonable basis for believing would be injurious to the health and safety of persons or harmful to the environment if released into the workplace or the environment.

Examples of the types of materials and wastes considered hazardous are hazardous chemicals (e.g., toxic, ignitable, corrosive, and reactive materials), radioactive materials, and medical (infectious) waste. The characteristics of toxicity, ignitability, corrosivity, and reactivity are defined in CCR Title 22 §66261.20-66261.24 and are summarized below:

> **Toxic Substances:** Toxic substances may cause short-term or long-lasting health effects, ranging from temporary effects to permanent disability, or even death. For example, such substances can cause disorientation, acute allergic reactions, asphyxiation, skin irritation, or other adverse health effects if human exposure exceeds certain levels. (The level depends on the substances involved and are chemical-specific.) Carcinogens (substances that can cause cancer) are a special class of toxic substances. Examples of toxic substances include benzene (a component of gasoline and a suspected carcinogen) and methylene chloride (a common laboratory solvent and a suspected carcinogen).
>
> **Ignitable Substances:** Ignitable substances are hazardous because of their ability to burn. Gasoline, hexane, and natural gas are examples of ignitable substances.
>
> **Corrosive Materials:** Corrosive materials can cause severe burns. Corrosives include strong acids and bases such as sodium hydroxide (lye) or sulfuric acid (battery acid).
>
> **Reactive Materials:** Reactive materials may cause explosions or generate toxic gases. Explosives, pure sodium or potassium metals (which react violently with water), and cyanides are examples of reactive materials.

3.4.1.2 Federal Regulations

The USEPA is the primary federal agency charged with protecting human health and with safeguarding the natural environment over air, water, and land. The USEPA works to develop and enforce regulations that implement environmental laws enacted by Congress. The USEPA is responsible for researching and setting national standards for a variety of environmental programs, and delegates to states and Indian tribes the responsibility for issuing permits and for monitoring and enforcing compliance. Since 1970, Congress has enacted numerous environmental laws that pertain to hazardous materials, for the USEPA to implement as well as to other agencies at the federal, state and local level, as described in the following subsections.

Toxic Substances Control Act

The Toxic Substances Control Act (TSCA) was enacted by Congress in 1976 (see 15 U.S.C. §2601 et seq.) and gave the USEPA the authority to protect the public from unreasonable risk of injury to health or the environment by regulating the manufacture, sale, and use of chemicals currently produced or imported into the United States. The TSCA, however, does not address wastes produced as byproducts of manufacturing. The types of chemicals regulated by the act fall into two categories: existing and new. New chemicals are defined as "any chemical substance which is not included in the chemical substance list compiled and published under [TSCA] section 8(b)." This list included all of chemical substances manufactured or imported into the U.S. prior to December 1979. Existing chemicals include any chemical currently listed under section 8 (b). The distinction between existing and new chemicals is necessary as the act regulates each category of chemicals in different ways. The USEPA repeatedly screens both new and existing chemicals and can require reporting or testing of those that may pose an environmental or human-health hazard. The USEPA can ban the manufacture and import of those chemicals that pose an unreasonable risk.

Emergency Planning and Community Right-to-Know Act

The Emergency Planning and Community Right-to-Know Act (EPCRA) is a federal law adopted by Congress in 1986 that is designed to help communities plan for emergencies involving hazardous substances. EPCRA establishes requirements for federal, state and local governments, Indian tribes, and industry regarding emergency planning and "Community Right-to-Know" reporting on hazardous and toxic chemicals. The Community Right-to-Know provisions help increase the public's knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment. States and communities, working with facilities, can use the information to improve chemical safety and protect public health and the environment. There are four major provisions of EPCRA:

1) Emergency Planning (§§301 – 303) requires local governments to prepare chemical emergency response plans, and to review plans at least annually. These sections also require state governments to oversee and coordinate local planning efforts. Facilities that maintain Extremely Hazardous Substances (EHS) on-site (see 40 CFR Part 355 for the list of EHS chemicals) in quantities greater than corresponding "Threshold Planning Quantities" must cooperate in the preparation of the emergency plan.

2) Emergency Release Notification (§304) requires facilities to immediately report accidental releases of EHS chemicals and hazardous substances in quantities greater than corresponding Reportable Quantities (RQs) as defined under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to state and local officials. Information about accidental chemical releases must be made available to the public.

3) Hazardous Chemical Storage Reporting (§§311 – 312) requires facilities that manufacture, process, or store designated hazardous chemicals to make Material Safety Data Sheets (MSDSs) describing the properties and health effects of these chemicals available to state and local officials and local fire departments. These sections also require facilities to report to state and local officials and local fire departments, inventories of all on-site chemicals for which MSDSs exist. Lastly, information about chemical inventories at facilities and MSDSs must be available to the public.

4) Toxic Chemical Release Inventory (§313) requires facilities to annually complete and submit a Toxic Chemical Release Inventory Form for each Toxic Release Inventory (TRI) chemical that are manufactured or otherwise used above the applicable threshold quantities.

Implementation of EPCRA has been delegated to the State of California. The California Emergency Management Agency requires facilities to develop a Hazardous Materials Business Plan if they handle hazardous materials in quantities equal to or greater than 55 gallons, 500 pounds, or 200 cubic feet of gas or extremely hazardous substances above the threshold planning quantity. The Hazardous Materials Business Plan is provided to State and local emergency response agencies and includes inventories of hazardous materials, an emergency plan, and implements a training program for employees.

Hazardous Materials Transportation Act

The Hazardous Material Transportation Act (HMTA), adopted in 1975 (see 49 U.S.C. §§5101 – 5127), gave the Secretary of Transportation the regulatory and enforcement authority to provide adequate protection against the risks to life and property inherent in the transportation of hazardous material in commerce. The USDOT (see 49 CFR Parts 171-180) oversees the movement of hazardous materials at the federal level. The HMTA requires that carriers report accidental releases of hazardous materials to USDOT at the earliest practical moment. Other incidents that must be reported include deaths, injuries requiring hospitalization, and property damage exceeding $50,000. The hazardous material regulations also contain emergency response provisions which include incident reporting requirements. Reports of major incidents go to the National Response Center, which in turn is linked with CHEMTREC, a public service hotline established by the chemical manufacturing industry for emergency responders to obtain information and assistance for emergency incidents involving chemicals and hazardous materials.

Hazardous materials regulations are implemented by the Research and Special Programs Administration (RSPA) branch of the USDOT. The regulations cover the definition and classification of hazardous materials, communication of hazards to workers and the public, packaging and labeling requirements, operational rules for shippers, and training. These regulations apply to interstate, intrastate, and foreign commerce by air, rail, ships, and motor vehicles, and also cover hazardous waste shipments. The Federal Aviation Administration Office of Hazardous Materials Safety is responsible for overseeing the safe handling of hazardous materials aboard aircraft. The Federal Railroad Administration oversees the transportation of hazardous materials by rail. The U.S. Coast Guard regulates the bulk transport of hazardous materials by sea. The Federal Highway Administration (FHWA) is responsible for highway routing of hazardous materials and issuing highway safety permits.

<u>Hazardous Materials Waste Regulations</u>

Resource Conservation and Recovery Act: The Resource Conservation and Recovery Act (RCRA) was adopted in 1976 (see 40 CFR Parts 238-282) and authorizes the USEPA to control the generation, transportation, treatment, storage, and disposal of hazardous waste. The RCRA regulation specifies requirements for generators, including waste minimization methods, as well as for transporters and for treatment, storage, and disposal facilities. The RCRA regulation also includes restrictions on land disposal of wastes and used oil management standards. Under RCRA, hazardous wastes must be tracked from the time of generation to the point of disposal. In 1984, RCRA was amended with addition of the Hazardous and Solid Waste Amendments, which authorized increased enforcement by the USEPA, more strict hazardous waste standards, and a comprehensive UST program. Likewise, the Hazardous and Solid Waste Amendments focused on waste reduction and corrective action for hazardous releases. The use of certain techniques for the disposal of some hazardous wastes was specifically prohibited by the Hazardous and Solid Waste Amendments. Individual states may implement their own hazardous waste programs under RCRA, with approval by the USEPA.

Comprehensive Environmental Response, Compensation and Liability Act: The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), which is often commonly referred to as Superfund, is a federal statute that was enacted in 1980 to address abandoned sites containing hazardous waste and/or contamination. CERCLA was amended in 1986 by the Superfund Amendments and Reauthorization Act, and by the Small Business Liability Relief and Brownfields Revitalization Act of 2002.

CERCLA contains prohibitions and requirements concerning closed and abandoned hazardous waste sites; establishes liability of persons responsible for releases of hazardous waste at these sites; and creates a trust fund to provide for cleanup when no responsible party can be identified. The trust fund is funded largely by a tax on the chemical and petroleum industries. CERCLA also provides federal jurisdiction to respond directly to releases or impending releases of hazardous substances that may endanger public health or the environment.

CERCLA also enabled the revision of the National Contingency Plan (NCP) which provided the guidelines and procedures needed to respond to releases and threatened releases of hazardous substances, pollutants, or contaminants. The NCP also established the National Priorities List, which identifies hazardous waste sites eligible for long-term remedial action financed under the federal Superfund program.

Prevention of Accidental Releases and Risk Management Programs: Requirements pertaining to the prevention of accidental releases are promulgated in §112 (r) of the Clean Air Act Amendments of 1990 [42 U.S.C. §7401 et. seq.]. The objective of these requirements was to prevent the accidental release and to minimize the consequences of any such release of a hazardous substance. Under these provisions, facilities that produce, process, handle or store hazardous substance have a duty to: 1) identify hazards which may result from releases using hazard assessment techniques; 2) design and maintain a safe facility and take steps necessary to prevent releases; and, 3) minimize the consequence of accidental releases that occur.

In accordance with the requirements in §112 (r), USEPA adopted implementing guidelines in 40 CFR Part 68. Under this part, stationary sources with more than a threshold quantity of a regulated substance shall be evaluated to determine the potential for and impacts of accidental releases from any processes subject to the federal risk management requirements. Under certain conditions, the owner or operator of a stationary source may be required to develop and submit a Risk Management Plan (RMP). RMPs consist of three main elements: a hazard assessment that includes off-site consequences analyses and a five-year accident history, a prevention program, and an emergency response program.

Hazardous Material Worker Safety Requirements

Occupational Safety and Health Administration Act: The federal Occupational Safety and Health Administration (OSHA) is an agency of the United States Department of Labor that was created by Congress under the Occupational Safety and Health Act in 1970. OSHA is the agency responsible for assuring worker safety in the handling and use of chemicals in the workplace. Under the authority of the Occupational Safety and Health Act of 1970, OSHA has adopted numerous regulations pertaining to worker safety (see 29 CFR Part 1910). These regulations set standards for safe workplaces and work practices, including the reporting of accidents and occupational injuries. Some OSHA regulations contain standards relating to hazardous materials handling to protect workers who handle toxic, flammable, reactive, or explosive materials, including workplace conditions, employee protection requirements, first aid, and fire protection, as well as material handling and storage. For example, facilities which use, store, manufacture, handle, process, or move hazardous materials are required to conduct employee safety training, have available and know how to use safety equipment, prepare illness prevention programs, provide hazardous substance exposure warnings, prepare emergency response plans, and prepare a fire prevention plan.

Procedures and standards for safe handling, storage, operation, remediation, and emergency response activities involving hazardous materials and waste are promulgated in 29 CFR Part 1910, Subpart H. Some key subsections in 29 CFR Part 1910, Subpart H are §1910.106 -Flammable Liquids and §1910.120 - Hazardous Waste Operations and Emergency Response. In particular, the Hazardous Waste Operations and Emergency Response regulations contain requirements for worker training programs, medical surveillance for workers engaging in the handling of hazardous materials or wastes, and waste site emergency and remediation planning, for those who are engaged in specific clean-up, corrective action, hazardous material handling, and emergency response activities (see 29 CFR Part 1910 Subpart H, §1910.120 (a)(1)(i-v) and §1926.65 (a)(1)(i-v)).

Process Safety Management: As part of the numerous regulations pertaining to worker safety adopted by OSHA, specific requirements that pertain to Process Safety Management (PSM) of Highly Hazardous Chemicals were adopted in 29 CFR Part 1910 Subpart H, §1910.119 and 8 CCR §5189 to protect workers at facilities that have toxic, flammable, reactive or explosive materials. PSM program elements are aimed at preventing or minimizing the consequences of catastrophic releases of chemicals and include process hazard analyses, formal training programs for employees and contractors, investigation of equipment mechanical integrity, and an emergency response plan. Specifically, the PSM program requires facilities that use, store, manufacture, handle, process, or move hazardous materials to conduct employee safety training; have an inventory of safety equipment relevant to potential hazards; have knowledge on use of the safety equipment; prepare an illness prevention program; provide hazardous substance exposure warnings; prepare an emergency response plan; and prepare a fire prevention plan.

Emergency Action Plan: An Emergency Action Plan (EAP) is a written document required by OSHA standards promulgated in 29 CFR Part 1910, Subpart E, §1910.38 (a) to facilitate and organize a safe employer and employee response during workplace emergencies. An EAP is required by all that are required to have fire extinguishers. At a minimum, an EAP must include the following: 1) a means of reporting fires and other emergencies; 2) evacuation procedures and emergency escape route assignments; 3) procedures to be followed by employees who remain to operate critical plant operations before they evacuate; 4) procedures to account for all employees after an emergency evacuation has been completed; 5) rescue and medical duties for those employees who are to perform them; and, 6) names or job titles of persons who can be contacted for further information or explanation of duties under the plan.

National Fire Regulations: The National Fire Codes (NFC), Title 45, published by the National Fire Protection Association (NFPA) contains standards for laboratories using chemicals, which are not requirements, but are generally employed by organizations in order to protect workers. These standards provide basic protection of life and property in laboratory work areas through prevention and control of fires and explosions, and also serve to protect personnel from exposure to non-fire health hazards.

In addition to the NFC, the NFPA adopted a hazard rating system which is promulgated in NFPA 704 - Standard System for the Identification of the Hazards of Materials for Emergency Response. NFPA 704 is a "standard (that) provides a readily recognized, easily understood system for identifying specific hazards and their severity using spatial, visual, and numerical methods to describe in simple terms the relative hazards of a material. It addresses the health, flammability, instability, and related hazards that may be presented as short-term, acute exposures that are most likely to occur as a result of fire, spill, or similar emergency[1]." In addition, the hazard ratings per NFPA 704 are used by emergency personnel to quickly and easily identify the risks posed by nearby hazardous materials in order to help determine what, if any, specialty equipment should

[1] NFPA, FAQ for Standard 704, 2007 edition. http://www.nfpa.org/Assets/files/AboutTheCodes/704/704-2007_FAQs.pdf

be used, procedures followed, or precautions taken during the first moments of an emergency response. The scale is divided into four color-coded categories, with blue indicating level of health hazard, red indicating the flammability hazard, yellow indicating the chemical reactivity, and white containing special codes for unique hazards such as corrosivity and radioactivity. Each hazard category is rated on a scale from 0 (no hazard; normal substance) to 4 (extreme risk). Table 3.4-1 summarizes what the codes mean for each hazards category.

TABLE 3.4-1
NFPA 704 Hazards Rating Codes

Hazard Rating Code	Health (Blue)	Flammability (Red)	Reactivity (Yellow)	Special (White)
4 = Extreme	Very short exposure could cause death or major residual injury (extreme hazard)	Will rapidly or completely vaporize at normal atmospheric pressure and temperature, or is readily dispersed in air and will burn readily. Flash point below 73 °F.	Readily capable of detonation or explosive decomposition at normal temperatures and pressures.	~~W~~ = Reacts with water in an unusual or dangerous manner.
3 = High	Short exposure could cause serious temporary or moderate residual injury	Liquids and solids that can be ignited under almost all ambient temperature conditions. Flash point between 73 °F and 100 °F.	Capable of detonation or explosive decomposition but requires a strong initiating source, must be heated under confinement before initiation, reacts explosively with water, or will detonate if severely shocked.	**OXY** = Oxidizer
2 = Moderate	Intense or continued but not chronic exposure could cause temporary incapacitation or possible residual injury.	Must be moderately heated or exposed to relatively high ambient temperature before ignition can occur. Flash point between 100 °F and 200 °F.	Undergoes violent chemical change at elevated temperatures and pressures, reacts violently with water, or may form explosive mixtures with water.	**SA** = Simple asphyxiant gas (includes nitrogen, helium, neon, argon, krypton and xenon).
1 = Slight	Exposure would cause irritation with only minor residual injury.	Must be heated before ignition can occur. Flash point over 200 °F.	Normally stable, but can become unstable at elevated temperatures and pressures	Not Applicable
0 = Insignificant	Poses no health hazard, no precautions necessary	Will not burn	Normally stable, even under fire exposure conditions, and is not reactive with water.	Not applicable

In addition to the above information, there are also a number of other physical or chemical properties may cause a substance to be a fire hazard. With respect to determining whether any substance is classified as a fire hazard, MSDS lists the National Fire Protection Association 704 flammability hazard ratings (e.g., NFPA 704). NFPA 704 is a standard that provides a readily recognized, easily understood system for identifying flammability hazards and their severity using spatial, visual, and numerical methods to describe in simple terms the relative flammability hazards of a material.

Although substances can have the same NFPA 704 Flammability Ratings Code, other factors can make each substance's fire hazard very different from each other. For this reason, additional chemical characteristics, such as auto-ignition temperature, boiling point, evaporation rate, flash point, lower explosive limit (LEL), upper explosive limit (UEL), and vapor pressure, are also considered when determining whether a substance is fire hazard. The following is a brief description of each of these chemical characteristics.

Auto-ignition Temperature: The auto-ignition temperature of a substance is the lowest temperature at which it will spontaneously ignite in a normal atmosphere without an external source of ignition, such as a flame or spark.

Boiling Point: The boiling point of a substance is the temperature at which the vapor pressure of the liquid equals the environmental pressure surrounding the liquid. Boiling is a process in which molecules anywhere in the liquid escape, resulting in the formation of vapor bubbles within the liquid.

Evaporation Rate: Evaporation rate is the rate at which a material will vaporize (evaporate, change from liquid to a vapor) compared to the rate of vaporization of a specific known material. This quantity is a represented as a unitless ratio. For example, a substance with a high evaporation rate will readily form a vapor which can be inhaled or explode, and thus have a higher hazard risk. Evaporation rates generally have an inverse relationship to boiling points (i.e., the higher the boiling point, the lower the rate of evaporation).

Flash Point: Flash point is the lowest temperature at which a volatile liquid can vaporize to form an ignitable mixture in air. Measuring a liquid's flash point requires an ignition source. At the flash point, the vapor may cease to burn when the source of ignition is removed. There are different methods that can be used to determine the flashpoint of a solvent but the most frequently used method is the Tagliabue Closed Cup standard (ASTM D56), also known as the TCC. The flashpoint is determined by a TCC laboratory device which is used to determine the flash point of mobile petroleum liquids with flash point temperatures below 175 degrees Fahrenheit (79.4 degrees Centigrade).

Flash point is a particularly important measure of the fire hazard of a substance. For example, the Consumer Products Safety Commission (CPSC) promulgated Labeling and Banning Requirements for Chemicals and Other Hazardous Substances in 15 U.S.C. §1261 and 16 CFR Part 1500. Per the CPSC, the flammability of a product is defined in 16 CFR Part 1500.3 (c)(6) and is based on flash point. For example, a liquid needs to be labeled as: 1) "Extremely Flammable" if the flash point is below 20 degrees Fahrenheit; 2) "Flammable" if the flash point is above 20 degrees Fahrenheit but less than 100 degrees Fahrenheit; or, 3) "Combustible" if the flash point is above 100 degrees Fahrenheit up to and including 150 degrees Fahrenheit.

Lower Explosive Limit (LEL): The lower explosive limit of a gas or a vapor is the limiting concentration (in air) that is needed for the gas to ignite and explode or the lowest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (e.g., arc, flame, or heat). If the concentration of a substance in air is below the LEL, there is not enough fuel to continue an explosion. In other words, concentrations lower than the LEL are "too lean" to burn. For example, methane gas has a LEL of 4.4 percent (at 138 degrees Centigrade) by volume, meaning 4.4 percent of the total volume of the air consists of methane. At 20 degrees Centigrade, the LEL for methane is 5.1 percent by volume. If the atmosphere has less than~~t~~ 5.1 percent methane, an explosion cannot occur even if a source of ignition is present. When the concentration of methane reaches 5.1 percent, an explosion can occur if there is an ignition source.

Upper Explosive Limit (UEL): The upper explosive limit of a gas or a vapor is the highest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (e.g., arc, flame, or heat). Concentrations of a substance in air above the UEL are "too rich" to burn.

Vapor Pressure: Vapor pressure is an indicator of a chemical's tendency to evaporate into gaseous form.

Health Hazards Guidance: In addition to fire impacts, health hazards can also be generated due to exposure of chemicals present in both conventional as well as reformulated products. Using available toxicological information to evaluate potential human health impacts associated with conventional solvents and potential replacement solvents, the toxicity of the conventional solvents can be compared to solvents expected to be used in reformulated products. As a measure of a chemical's potential health hazards, the following values need to be considered: the Threshold Limit Values (TLVs) established by the American Conference of Governmental Industrial Hygiene (ACGIH), OSHA's Permissible Exposure Limits (PELs), the Immediately Dangerous to Life and Health (IDLH) levels recommended by the National Institute for Occupational Safety and Health (NIOSH), permissible exposure limits (PEL) established by OSHA, and health hazards developed by the National Safety Council. The following is a brief description of each of these values.

Threshold Limit Values (TLVs): The TLV of a chemical substance is a level to which it is believed a worker can be exposed day after day for a working lifetime without adverse health effects. The TLV is an estimate based on the known toxicity in humans or animals of a given chemical substance, and the reliability and accuracy of the latest sampling and analytical methods. The TLV for chemical substances is defined as a concentration in air, typically for inhalation or skin exposure. Its units are in parts per million (ppm) for gases and in milligrams per cubic meter (mg/m^3) for particulates. The TLV is a recommended guideline by ACGIH.

Permissible Exposure Limits (PEL): The PEL is a legal limit, usually expressed in ppm, established by OSHA to protect workers against the health effects of exposure to hazardous substances. PELs are regulatory limits on the amount or concentration of a substance in the air. A PEL is usually given as a time-weighted average (TWA), although some are short-term exposure limits (STEL) or ceiling limits. A TWA is the average exposure over a specified period of time, usually eight hours. This means that, for limited periods, a worker may be exposed to concentrations higher than the PEL, so long as the average concentration over eight hours remains lower. A short-term exposure limit is one that addresses the average exposure over a 15 to 30 minute period of maximum exposure during a single work shift. A ceiling limit is one that may not be exceeded for any period of time, and is applied to irritants and other materials that have immediate effects. The OSHA PELs are published in 29 CFR 1910.1000, Table Z1.

Immediately Dangerous to Life and Health (IDLH): IDLH is an acronym defined by NIOSH as exposure to airborne contaminants that is "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment." IDLH values are often used to guide the selection of breathing apparatus that are made available to workers or firefighters in specific situations.

Oil and Pipeline Regulations and Oversight

Oil Pollution Act: The Oil Pollution Act was signed into law in 1990 to give the federal government authority to better respond to oil spills (see 33 U.S.C. §2701). The Oil Pollution Act improved the federal government's ability to prevent and respond to oil spills, including provision of money and resources. The Oil Pollution Act establishes polluter liability, gives states enforcement rights in navigable waters of the State, mandates the development of spill control and response plans for all vessels and facilities, increases fines and enforcement mechanisms, and establishes a federal trust fund for financing clean-up.

The Oil Pollution Act also establishes the National Oil Spill Liability Trust Fund to provide financing for cases in which the responsible party is either not readily identifiable, or refuses to pay the cleanup/damage costs. In addition, the Oil Pollution Act expands provisions of the National Oil and Hazardous Substances Pollution Contingency Plan, more commonly called the National Contingency Plan, requiring the federal government to direct all public and private oil spill response efforts. It also requires area committees, composed of federal, state, and local government officials, to develop detailed, location-specific area contingency plans. In addition, the Oil Pollution Act directs owners and operators of vessels, and certain facilities that pose a serious threat to the environment, to prepare their own specific facility response plans. The Oil Pollution Act increases penalties for regulatory non-compliance by responsible parties; gives the federal government broad enforcement authority; and provides individual states the authority to establish their own laws governing oil spills, prevention measures, and response methods. The Oil Pollution Act requires oil storage facilities and vessels to submit to the Federal government plans detailing how they will respond to large discharges. The USEPA has published regulations for aboveground storage facilities and the Coast Guard has done the same for oil tankers.

Oil Pollution Prevention Regulation: In 1973, the USEPA issued the Oil Pollution Prevention regulation (see 40 CFR 112)**,** to address the oil spill prevention provisions contained in the Clean Water Act of 1972. The Spill Prevention, Control, and Countermeasure (SPCC) Rule is part of the Oil Pollution Prevention regulations (see 40 CFR Part 112, Subparts A - C). Specifically, the SPCC rule includes requirements for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The rule requires specific facilities to prepare, amend, and implement SPCC Plans. SPCC Plans require applicable facilities to take steps to prevent oil spills including: 1) using suitable storage containers/tanks; 2) providing overfill prevention (e.g., high-level alarms); 3) providing secondary containment for bulk storage tanks; 4) providing secondary containment to catch oil spills during transfer activities; and, 5) periodically inspecting and testing pipes and containers.

U.S. Department of Transportation, Office of Pipeline Safety: The Office of Pipeline Safety, within the USDOT, Pipeline and Hazards Material Safety Administration, has jurisdictional responsibility for developing regulations and standards to ensure the safe and secure movement of hazardous liquid and gas pipelines under its jurisdiction in the United States. The Office of Pipeline Safety has the following key responsibilities:

- Support the operation of, and coordinate with the United States Coast Guard on the National Response Center and serve as a liaison with the Department of Homeland Security and the Federal Emergency Management Agency on matters involving pipeline safety;

- Develop and maintain partnerships with other federal, state, and local agencies, public interest groups, tribal governments, and the regulated industry and other underground utilities to address threats to pipeline integrity, service, and reliability and to share responsibility for the safety of communities;

- Administer pipeline safety regulatory programs and develops regulatory policy involving pipeline safety;

- Oversee pipeline operator implementation of risk management and risk-based programs and administer a national pipeline inspection and enforcement program;

- Provide technical and resource assistance for state pipeline safety programs to ensure oversight of intrastate pipeline systems and educational programs at the local level; and,

- Support the development and conduct of pipeline safety training programs for federal and state regulatory and compliance staff and the pipeline industry.

49 CFR Parts 178 – 185 relates to the role of transportation, including pipelines, in the United States. 49 CFR Parts 186-199 establishes minimum pipeline safety standards. The Office of the State Fire Marshal works in partnership with the Federal Pipeline and Hazardous Materials Safety Administration to assure pipeline operators are meeting requirements for safe, reliable, and environmentally sound operation of their facilities for intrastate pipelines within California.

Chemical Facility Anti-Terrorism Standards: The Federal Department of Homeland Security is responsible for implementing the Chemical Facility Anti-Terrorism Standards that were adopted in 2007 (see 6 CFR Part 27). These standards establish risk-based performance standards for the security of chemical facilities and require covered chemical facilities to prepare Security Vulnerability Assessments, which identify facility security vulnerabilities, and to develop and implement Site Security Plans.

3.4.1.3 State Regulations

Hazardous Materials and Waste Regulations

Hazardous Waste Control Law: California's Hazardous Waste Control Law is administered by the California Environmental Protection Agency (CalEPA) to regulate hazardous wastes within the State of California. While the California Hazardous Waste Control Law is generally more stringent than RCRA, both the state and federal laws apply in California. The California Department of Toxic Substances Control (DTSC) is the primary agency in charge of enforcing both the federal and state hazardous materials laws in California. The DTSC regulates hazardous waste, oversees the cleanup of existing contamination, and pursues avenues to reduce hazardous waste produced in California. The DTSC regulates hazardous waste in California under the authority of RCRA, the Hazardous Waste Control Law, and the HSC. Under the direction of the CalEPA, the DTSC maintains the Cortese and Envirostor databases of hazardous materials and waste sites as specified under Government Code §65962.5.

The Hazardous Waste Control Law (22 CCR Chapter 11, Appendix X) also lists 791 chemicals and approximately 300 common materials which may be hazardous; establishes criteria for identifying, packaging, and labeling hazardous wastes; prescribes management controls; establishes permit requirements for treatment, storage, disposal, and transportation; and identifies some wastes that cannot be disposed of in landfills.

California Occupational Safety and Health Administration: The California Occupational Safety and Health Administration (CalOSHA) is the primary state agency responsible for worker safety in the handling and use of chemicals in the workplace. CalOSHA requires employers to monitor worker exposure to listed hazardous substances and notify workers of exposure (8 CCR §§337 - 340). The regulations specify requirements for employee training, availability of safety equipment, accident-prevention programs, and hazardous substance exposure warnings. CalOSHA's standards are generally more stringent than federal regulations.

Hazardous Materials Release Notification: Many state statutes require emergency notification when a hazardous chemical is released, including:

- California HSC §25270.7, §25270.8, and §25507;
- California Vehicle Code §23112.5;
- California Public Utilities Code §7673 (General Orders #22-B, 161);
- California Government Code §51018 and §8670.25.5 (a);
- California Water Code §13271 and §13272; and,
- California Labor Code §6409.1 (b)(10).

California Accident Release Prevention (CalARP) Program: The California Accident Release Prevention Program (19 CCR Division 2, Chapter 4.5) requires the preparation of Risk Management Plans (RMPs). CalARP requires stationary sources with more than a threshold quantity of a regulated substance to be evaluated to determine the potential for and impacts of accidental releases from any processes subject to state risk management requirements. RMPs are documents prepared by the owner or operator of a stationary source containing detailed information including: 1) regulated substances held onsite at the stationary source; 2) offsite consequences of an accidental release of a regulated substance; 3) the accident history at the stationary source; 4) the emergency response program for the stationary source; 5) coordination with local emergency responders; 6) hazard review or process hazard analysis; 7) operating procedures at the stationary source; 8) training of the stationary source's personnel; 9) maintenance and mechanical integrity of the stationary source's physical plant; and, 10) incident investigation. The CalARP program is implemented at the local government level by Certified Unified Program Agencies (CUPAs) also known as Administering Agencies (AAs). Typically, local fire departments are the administering agencies of the CalARP program because they frequently are the first responders in the event of a release.

Unified Hazardous Waste and Hazardous Materials Management Regulatory Program: The Unified Hazardous Waste and Hazardous Materials Management Regulatory Program (Unified Program) as promulgated by CalEPA in CCR, Title 27, Chapter 6.11 requires the administrative consolidation of six hazardous materials and waste programs (program elements) under one agency, a CUPA. The Unified Program administered by the State of California consolidates, coordinates, and makes consistent the administrative requirements, permits, inspections, and enforcement activities for the state's environmental and emergency management programs, which include Hazardous Waste Generator and On-Site Hazardous Waste Treatment Programs ("Tiered Permitting"); Above ground SPCC Program; Hazardous Materials Release Response Plans and Inventories (business plans); the CalARP Program; the UST Program; and the Uniform Fire Code Plans and Inventory Requirements. The Unified Program is implemented at the local government level by CUPAs.

Hazardous Materials Management Act: California HSC, Division 20, Chapter 6.95 requires any business handling more than a specified amount of hazardous or extremely hazardous materials, termed a "reportable quantity," to submit a Hazardous Materials Business Plan to its CUPA. Business plans must include an inventory of the types, quantities, and locations of hazardous materials at the facility. Businesses are required to update their business plans at least once every three years and the chemical portion of their plans every year. Also, business plans must include emergency response plans and procedures to be used in the event of a significant or threatened significant release of a hazardous material. These plans need to identify the procedures to follow for immediate notification to all appropriate agencies and personnel of a release, identification of local emergency medical assistance appropriate for potential accident scenarios, contact information for all company emergency coordinators, a listing and location of emergency equipment at the business, an evacuation plan, and a training program for business personnel. The requirements for hazardous materials business plans are specified in the California HSC and 19 CCR.

Hazardous Materials Transportation in California: California regulates the transportation of hazardous waste originating or passing through the State in Title 13, CCR. The California Highway Patrol (CHP) and the California Department of Transportation (Caltrans) have primary responsibility for enforcing federal and State regulations and responding to hazardous materials transportation emergencies. The CHP enforces materials and hazardous waste labeling and packing regulations that prevent leakage and spills of material in transit and provide detailed information to cleanup crews in the event of an incident. Vehicle and equipment inspection, shipment preparation, container identification, and shipping documentation are all part of the responsibility of the CHP. Caltrans has emergency chemical spill identification teams at locations throughout California.

California Fire Code: While NFC Standard 45 and NFPA 704 are regarded as nationally recognized standards, the California Fire Code (24 CCR) also contains state standards for the use and storage of hazardous materials and special standards for buildings where hazardous materials are found. Some of these regulations consist of amendments to NFC Standard 45. State Fire Code regulations require emergency pre-fire plans to include training programs in first aid, the use of fire equipment, and methods of evacuation.

3.4.1.4 Local Regulations

<u>SCAQMD</u>

SCAQMD Rule 1166 – Volatile Organic Compound Emissions from Decontamination of Soil: SCAQMD Rule 1166 establishes requirements to control the emission of VOCs from excavating, grading, handling, and treating soil contaminated from leakage, spillage, or other means of VOCs deposition. Rule 1166 stipulates that any parties planning on excavating, grading, handling, transporting, or treating soils contaminated with VOCs must first apply for and obtain, and operate pursuant to, a mitigation plan approved by the Executive Officer prior to commencement of operation. BACT is required during all phases of remediation of soil contaminated with VOCs. Rule 1166 also sets forth testing, record keeping and reporting procedures that must be followed at all times. Non-compliance with Rule 1166 can result in the revocation of the approved mitigation plan, the owner and/or the operator being served with a Notice of Violation for creating a public nuisance, or an order to halt the offending operation until the public nuisance is mitigated to the satisfaction of the Executive Officer.

<u>Regulations From Other Local Agencies</u>

In addition to the SCAQMD, other local agencies throughout the four counties in the district and their respective fire departments have a variety of local laws that regulate reporting, storage and handling of hazardous materials and wastes.

Los Angeles County: The Office of Emergency Management is responsible for organizing and directing the preparedness efforts of the Emergency Management Organization of Los Angeles County. Los Angeles County's policies towards hazardous materials management include enforcing stringent site investigations for factors related to hazards; limiting the development in high hazard areas, such as floodplains, high fire hazard areas, and seismic hazard zones; facilitating safe transportation, use, and storage of hazardous materials; supporting lead paint abatement; remediating Brownfield sites; encouraging the purchase of homes on the Federal Emergency Management Agency (FEMA) Repeat Hazard list and designating the land as open space; enforcing restrictions on access to important energy sites; limiting development downslope from aqueducts; promoting safe alternatives to chemical-based products in households; and prohibiting development in floodways. The county has defined effective emergency response management capabilities to include supporting county emergency providers with reaching their response time goals; promoting the participation and coordination of emergency response management between cities and other counties at all levels of government; coordinating with other county and public agency emergency planning and response activities; and encouraging the development of an early warning system for tsunamis, floods and wildfires.

Orange County: The regulatory agency responsible for enforcement, as well as inspection of pipelines transporting hazardous materials, is the California State Fire Marshal's Office, Hazardous Liquid Pipeline Division. The Orange County Health Care Agency (OCHCA) has been designated by the Board of Supervisors as the agency to enforce the UST program. The OCHCA UST Program regulates approximately 7,000 of the 9,500 underground tanks in Orange County. The program includes conducting regular inspections of underground tanks; oversight of new tank installations; issuance of permits; regulation of repair and closure of tanks; ensuring the mitigation of leaking USTs; pursuing enforcement action; and educating and assisting the industries and general public as to the laws and regulations governing USTs.

Under mandate from the California HSC, the Orange County Fire Authority is the designated agency to inventory the distribution of hazardous materials in commercial or industrial occupancies, develop and implement emergency plans, and require businesses that handle hazardous materials to develop emergency plans do deal with these materials.

Orange County's Hazardous Materials Program Office is responsible for facilitating the coordination of various parts of the County's hazardous materials program; assisting in coordinating County hazardous materials activities with outside agencies and organization; providing comprehensive, coordinated analysis of hazardous materials issues; and directing the preparation, implementation, and modification of the county's Hazardous Waste Management Plan. With regard to San Onofre Nuclear Generating Station, in an effort to prepare those who live and work in areas outside, but adjacent to SONGS, the federal and state governments have established three levels of emergency zones. Orange County is responsible for its own emergency plans concerning a nuclear power plant accident, and the Incident Response Plan is updated regularly.

San Bernardino County: San Bernardino County's Hazardous Waste Management Plan (HWMP) serves as the primary planning document for the management of hazardous waste in San Bernardino County. The HWMP identifies the types and amounts of wastes generated; establishes programs for managing these wastes; identifies an application review process for the siting of specified hazardous waste facilities; identifies mechanisms for reducing the amount of waste generated; and identifies goals, policies, and actions for achieving effective hazardous waste management. One of the county's stated goals is to minimize the generation of hazardous waste and reduce the risk posed by storage, handling, transportation, and disposal of hazardous wastes. In addition, the county will protect its residents and visitors from injury and loss of life and protect property from fires by deploying firefighters and requiring new land developments to prepare site-specific fire protection plans.

Riverside County: Through its membership in the Southern California Hazardous Waste Management Authority (SCHWMA), the County of Riverside has agreed to work on a regional level to solve problems involving hazardous waste. SCHWMA was formed through a joint powers agreement between Santa Barbara, Ventura, San Bernardino, Orange, San Diego, Imperial, and Riverside Counties and the Cities of Los Angeles and San Diego. Working within the concept of "fair share," each SCHWMA county has agreed to take responsibility for the treatment and disposal of hazardous waste in an amount that is at least equal to the amount generated within that county. This responsibility can be met by siting hazardous waste management facilities (transfer, treatment, and/or repository) capable of processing an amount of waste equal to or larger than the amount generated within the county, or by creating intergovernmental agreements between counties to provide compensation to a county for taking another county's waste, or through a combination of both facility siting and intergovernmental agreements. When and where a facility is to be sited is primarily a function of the private market. However, once an application to site a facility has been received, the county will review the requested facility and its location against a set of established siting criteria to ensure that the location is appropriate and may deny the application based on the findings of this review. The County of Riverside does not presently have any of these facilities within its jurisdiction and, therefore, must rely on intergovernmental agreements to fulfill its fair share responsibility to SCHWMA.

3.4.2 Emergency Response To Hazardous Materials And Waste Incidents

The California Emergency Management Agency (CalEMA) exists to enhance safety and preparedness in California through strong leadership, collaboration, and meaningful partnerships. The goal of CalEMA is to protect lives and property by effectively preparing for, preventing, responding to, and recovering from all threats, crimes, hazards, and emergencies. CalEMA under the Fire and Rescue Division coordinates statewide implementation of hazardous materials accident prevention and emergency response programs for all types of hazardous materials incidents and threats. In response to any hazardous materials emergency, CalEMA is called upon to provide state and local emergency managers with emergency coordination and technical assistance.

Pursuant to the Emergency Services Act, the State of California has developed an Emergency Response Plan to coordinate emergency services provided by federal, state, and local government agencies and private persons. Response to hazardous materials incidents is one part of this plan. The Plan is administered by CalEMA which coordinates the responses of other agencies. Six mutual aid and Local Emergency Planning Committee (LEPC) regions have been identified for California that are divided into three areas of the state designated as the Coastal (Region II, which includes 16 counties with 151 incorporated cities and a population of about eight million people.), Inland (Region III, Region IV and Region V, which includes 31 counties with 123 incorporated cities and a population of about seven million people), and Southern (Region I and Region VI, which includes 11 counties with 226 incorporated cities and a population of about 21.6 million people). The SCAQMD jurisdiction covers portions of Region I and Region VI.

In addition, pursuant to the Hazardous Materials Release Response Plans and Inventory Law of 1985, local agencies are required to develop "area plans" for response to releases of hazardous materials and wastes. These emergency response plans depend to a large extent on the business plans submitted by persons who handle hazardous materials. An area plan must include pre-emergency planning of procedures for emergency response, notification, coordination of affected government agencies and responsible parties, training, and follow-up.

3.4.3 Hazardous Materials Incidents

Hazardous materials move through southern California by a variety of modes including truck, rail, air, ship, and pipeline. The movement of hazardous materials implies a degree of risk, depending on the materials being moved, the mode of transport, and numerous other factors (e.g., weather).

Hazardous materials move through the region by a variety of modes: Truck, rail, air, ship, and pipeline. According to the USDOT Office of Hazardous Materials Safety (OHMS), hazardous materials shipments can be regarded as equivalent to deliveries, but any given shipment may involve one or more movements or trip segments that may occur by different routes (e.g., rail transport with final delivery by truck). According to the Commodity Flow Survey data (USDOT, 2010), there were approximately 2.3 billion tons of hazardous materials shipments in the United States in 2007. Table 3.4-2 indicates that trucks move more than 50 percent of total hazardous materials shipped via all transportation modes from a location in the U.S. By contrast, rail accounts of only six percent of total shipments of hazardous materials (USDOT, 2010).

TABLE 3.4-2
Hazardous Material Shipments in the United States

Mode	Total Commercial Freight (thousand tons)	Hazardous Materials Shipped (thousand tons)	Percent of Hazardous Materials Shipped
Truck	8,778,713	1,202,825	13.7%
Rail	1,861,307	129,743	7.0%
Water	403,639	149,794	37.1%
Pipeline	650,859	628,905	96.6%
TOTAL	**11,694,518**	**2,111,267**	**18.1%**

Source: USDOT, 2010.

The movement of hazardous materials through the U.S. transportation system represents almost 18 percent of total tonnage for all freight shipments as measured by the Commodity Flow Survey. The total commercial freight moved in 2007 in California by all transportation modes was 900,817 thousand tons, of which about 738,550 thousand tons were moved by truck (USDOT, 2010).

The California Hazardous Materials Incident Reporting System (CHMIRS) is a post-incident reporting system to collect data on incidents involving the accidental release of hazardous materials in California. Information on accidental releases of hazardous materials are reported to and maintained by CalEMA. While information on accidental releases are reported to CalEMA, according to discussions with Mr. Greg Renick of CalEMA on July 25, 2012, CalEMA no longer conducts statistical evaluations of the releases (e.g., total number of releases per year) for the entire State, or data by county. The USDOT Pipeline and Hazardous Materials Safety Administration provides access to retrieve data from the Incident Reports Database, which also includes non-pipeline incidents (e.g., truck and rail events). Incident data and summary statistics (e.g., release date, geographical location for state and county) and type of material released, are available online from the Hazardous Materials Incident Report Form 5800.1.

Table 3.4-3 provides a summary of the reported hazardous material incidents for Los Angeles, Orange, Riverside, and San Bernardino counties for 2010 and 2011 from the Hazardous Materials Incident Report Form 5800.1. Data presented is for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

In 2010, there were a total of 672 incidents reported for Los Angeles, Orange, Riverside and San Bernardino counties, and in 2011 a total of 698 incidents four these four counties. San Bernardino and Los Angeles counties accounted for the largest number of incidents, followed by Orange and Riverside counties.

TABLE 3.4-3
Reported Hazardous Materials Incidents for 2010 and 2011

County	2010	2011
Los Angles	273	256
Orange	71	93
Riverside	46	51
San Bernardino	282	298
Total	**672**	**698**

3.4.4 Hazards Associated With Air Pollution Control and Alternative Fuels

The SCAQMD has evaluated the hazards associated with previous AQMPs, proposed SCAQMD rules, and non-SCAQMD projects where the SCAQMD is the Lead Agency pursuant to CEQA. The analyses covered a range of potential air pollution control technologies and equipment. EIRs prepared for the previous AQMPs have specifically evaluated hazard impacts from: 1) add-on control equipment; and, 2) alternative fuels.

Add-on pollution control technologies which have been previously analyzed for hazards include: carbon adsorption, incineration, post-combustion flue-gas treatment, SCR and SNCR, scrubbers, bag filters, and electrostatic precipitators. The use of add-on pollution control equipment may concentrate or utilize hazardous materials. A malfunction or accident when using add-on pollution control equipment could potentially expose people to hazardous materials, explosions, or fires. The SCAQMD has determined that the transport, use, and storage of ammonia, both aqueous and anhydrous, (used in SCR and SNCR systems) may have significant hazard impacts in the event of an accidental release. Further analyses have indicated that the use of aqueous ammonia (instead of anhydrous ammonia) can usually reduce the hazards associated with ammonia use in SCR and SNCR systems to less than significant.

Alternative fuels may be used to reduce emissions from both stationary source equipment and motor vehicles. The alternative fuels which have been analyzed include reformulated gasoline, methanol, compressed natural gas, LPG or propane, and electrically charged batteries. Like conventional fossil fuels, alternative fuels may create fire hazards, explosions or accidental releases during fuel transport, storage, dispensing, and use. Electric batteries also present a slight fire and explosion hazards due to the presence of reactive compounds, which may be subjected to high temperatures.

Ammonia

Ammonia is the primary hazardous chemical identified with the use of air pollution control equipment (e.g., SCR and SNCR systems). Ammonia, though not a carcinogen, can have chronic and acute health impacts. Therefore, a potential increase in the use of ammonia may increase the current existing risk setting associated with deliveries (e.g., truck and road accidents) and onsite or offsite spills for each facility that currently uses or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment. A toxic gas cloud is the release of a volatile chemical such as anhydrous ammonia that could form a cloud that migrates off-site, thus exposing individuals.

Anhydrous ammonia is heavier than air such that when released into the atmosphere, would form a cloud at ground level rather than be dispersed "Worst-case" conditions tend to arise when very low wind speeds coincide with the accidental release, which can allow the chemicals to accumulate rather than disperse. While there are existing facilities that are currently permitted to use anhydrous ammonia, for new construction, however, current SCAQMD policy no longer allows the use of anhydrous ammonia for the operation of air pollution control equipment. Instead, to minimize the hazards associated with ammonia used in the SCR or SNCR process, aqueous ammonia, 19 percent by volume, is typically required as a permit condition associated with the installation of SCR or SNCR equipment for the following reasons: 1) 19 percent aqueous ammonia does not travel as a dense gas like anhydrous ammonia; and, 2) 19 percent aqueous ammonia is not on any acutely hazardous material lists unlike anhydrous ammonia or aqueous ammonia at higher percentages.

LNG

LNG is essentially no different from the natural gas used in homes and businesses every day, except that it has been refrigerated to -259 °F at which point it becomes a clear, colorless, and odorless liquid. LNG currently is used as a combustion fuel in both stationary and mobile sources. As a liquid, natural gas occupies only one six-hundredth of its gaseous volume and can be transported economically between continents in special tankers. LNG weighs slightly less than half as much as water, so it floats on fresh or sea water. However, when LNG comes in contact with any warmer surface such as water or air, it evaporates very rapidly ("boil"), returning to its original, gaseous volume. As the LNG vaporizes, a vapor cloud resembling ground fog will form under relatively calm atmospheric conditions. The vapor cloud is initially heavier than air since it is so cold, but as it absorbs more heat, it becomes lighter than air, rises, and can be carried away by the wind. An LNG vapor cloud cannot explode in the open atmosphere, but it could burn.

LNG is considered a hazardous material. The primary safety concerns are the potential consequences of an LNG spill. LNG hazards result from three of its properties:

- Cryogenic temperatures
- Dispersion characteristics
- Flammability characteristics

The extreme cold of LNG can directly cause injury or damage. Although momentary contact on the skin can be harmless, extended contact will cause severe freeze burns. On contact with certain metals, such as ship decks, LNG can cause immediate cracking. Although not poisonous, exposure to the center of a vapor cloud could cause asphyxiation due to the absence of oxygen. LNG vapor clouds can ignite within the portion of the cloud where the concentration of natural gas is between a five and a 15 percent (by volume) mixture with air. To catch fire, however, this portion of the vapor cloud must encounter an ignition source. Otherwise, the LNG vapor cloud will simply dissipate into the atmosphere. An ignited LNG vapor cloud is very dangerous, because of its tremendous radiant heat output. Furthermore, as a vapor cloud continues to burn, the flame could burn back toward the evaporating pool of spilled liquid, ultimately burning the quickly evaporating natural gas immediately above the pool, giving the appearance of a "burning pool" or "pool fire." An ignited vapor cloud or a large LNG pool fire can cause extensive damage to life and property.

Spilled LNG would disperse faster on the ocean than on land, because water spills provide very limited opportunity for containment. Furthermore, LNG vaporizes more quickly on water, because the ocean provides an enormous heat source. For these reasons, most analysts conclude that the risks associated with shipping, loading, and off-loading LNG are much greater than those associated with land-based storage facilities. Preventing spills and responding immediately to spills should they occur are major factors in the design of LNG facilities (CEC, 2003).

Beyond routine industrial hazards and safety considerations, LNG presents specific safety considerations. In the event of an accidental release of LNG, the safety zone around a facility protects neighboring communities from personal injury, property damage or fire. The one and only case of an accident that affected the public was in Cleveland, Ohio in 1944. Research stemming from the Cleveland incident has influenced safety standards used today. Indeed, during the past four decades, growth in LNG use worldwide has led to a number of technologies and practices that will be used in the U.S. and elsewhere in North America as the LNG industry expands. Generally, multiple layers of protection create four critical safety conditions, all of which are integrated with a combination of industry standards and regulatory compliance. The four requirements for safety – primary containment, secondary containment, safeguard systems and separation distance apply across the LNG value chain, from production, liquefaction and shipping, to storage and re-gasification. The term "containment" means safe storage and isolation of LNG (Foss, 2003).

LPG

More than 350,000 light-and medium-duty vehicles travel the nation's highways using liquefied petroleum gas (LPG), while over four million vehicles use it worldwide. LPG is a mixture of several gases that is generally called "propane," in reference to the mixture's chief ingredient. LPG changes to the liquid state at the moderately high pressures found in an LPG vehicle's fuel tank. LPG is formed naturally, interspersed with deposits of petroleum and natural gas. Natural gas contains LPG, water vapor, and other impurities that must be removed before it can be transported in pipelines as a salable product. About 55 percent of the LPG processed in the U.S. is from natural gas purification. The other 45 percent comes from crude oil refining. Since a sizable amount of U.S. LPG is derived from petroleum, LPG does less to relieve the country's dependency on foreign oil than some other alternative fuels. However, because over 90 percent of the LPG used in the United States is produced here, LPG does help address the national security component of the nation's overall petroleum dependency problem.

Propane vehicles emit about one-third fewer reactive organic gases than gasoline-fueled vehicles. Nitrogen oxide and carbon monoxide emissions are also 20 percent and 60 percent less, respectively. Unlike gasoline-fueled vehicles, there are no evaporative emissions while

LPG vehicles are running or parked, because LPG fuel systems are tightly sealed. Small amounts of LPG may escape into the atmosphere during refueling, but these vapors are 50 percent less reactive than gasoline vapors, so they have less of a tendency to generate smog-forming ozone. LPG's extremely low sulfur content means that the fuel does not contribute significantly to acid rain.

Many propane vehicles are converted gasoline vehicles. The relatively inexpensive conversion kits include a regulator/vaporizer that changes liquid propane to a gaseous form and an air/fuel mixer that meters and mixes the fuel with filtered intake air before the mixture is drawn into the engine's combustion chambers. Also included in conversion kits is closed-loop feedback circuitry that continually monitors the oxygen content of the exhaust and adjusts the air/fuel ratio as necessary. This device communicates with the vehicle's onboard computer to keep the engine running at optimum efficiency. LPG vehicles additionally require a special fuel tank that is strong enough to withstand the LPG storage pressure of about 130 pounds per square inch. The gaseous nature of the fuel/air mixture in an LPG vehicle's combustion chambers eliminates the cold-start problems associated with liquid fuels. In contrast to gasoline engines, which produce high emission levels while running cold, LPG engine emissions remain similar whether the engine is cold or hot. Also, because LPG enters an engine's combustion chambers as a vapor, it does not strip oil from cylinder walls or dilute the oil when the engine is cold. This helps LPG powered engines to have a longer service life and reduced maintenance costs. Also helping in this regard is the fuel's high hydrogen-to-carbon ratio (C3H8), which enables propane powered vehicles to have less carbon build-up than gasoline- and diesel powered vehicles. LPG delivers roughly the same power, acceleration, and cruising speed characteristics as gasoline. It does yield a somewhat reduced driving range, however, because it contains only about 70-75 percent of the energy content of gasoline. Its high octane rating (around 105) means, though, that an LPG engine's power output and fuel efficiency can be increased beyond what would be possible with a gasoline engine without causing destructive "knocking." Such fine-tuning can help compensate for the fuel's lower energy density. Fleet owners find that propane costs are typically five to 30 percent less than those of gasoline. The cost of constructing an LPG fueling station is also similar to that of a comparably sized gasoline dispensing system. Fleet owners not wishing to establish fueling stations of their own may avail themselves of over 3,000 publicly accessible fueling stations nationwide.

Propane is an odorless, nonpoisonous gas that has the lowest flammability range of all alternative fuels. High concentrations of propane can displace oxygen in the air, though, causing the potential for asphyxiation. This problem is mitigated by the presence of ethyl mercaptan, which is an odorant that is added to warn of the presence of gas. While LPG itself does not irritate the skin, the liquefied gas becomes very cold upon escaping from a high-pressure tank, and may therefore cause frostbite, should it contact unprotected skin. As with gasoline, LPG can form explosive mixtures with air. Since the gas is slightly heavier than air, it may form a continuous stream that stretches a considerable distance from a leak or open container, which may lead to a flashback explosion upon contacting a source of ignition (USDOE, 2003).

While LPG is classified as a fire hazard, it is not classified as a toxic or as a hazardous air pollutant. LPG is a regulated substance subject to both the California and Federal RMP programs in accordance with the CCR, Title 19, §2770.4.1 and Chapter 40 of the CFR Part 68, §68.126[2]. A RMP is a document prepared by the owner or operator of a stationary source containing detailed information including, but not limited to:

- Regulated substances held onsite at the stationary source;
- Offsite consequences of an accidental release of a regulated substance;
- The accident history at the stationary source;
- The emergency response program for the stationary source;
- Coordination with local emergency responders;
- Hazard review or process hazard analysis;
- Operating procedures at the stationary source;
- Training of the stationary source's personnel;
- Maintenance and mechanical integrity of the stationary source's physical plant; and
- Incident investigation.

The threshold quantity for LPG (as propane) as a regulated substance for accidental release prevention is 10,000 pounds. However, when LPG is used as a fuel by an end user (as is frequently the case with residential portable and stationary storage tanks), or when it is held for retail sale as a fuel, it is excluded from these RMP requirements, even if the amount exceeds the threshold quantity.

On June 1, 2012, SCAQMD adopted Rule 1177 - Liquefied Petroleum Gas Transfer and Dispensing to reduce fugitive VOC emissions released during the transfer and dispensing of LPG at residential, commercial, industrial, chemical, agricultural and retail sales facilities. Rule 1177 applies to the transfer of LPG to and from stationary storage tanks, cylinders and cargo tanks, including bobtails, truck transports and rail tank cars, and into portable refillable cylinders. In addition, Rule 1177 requires the use of low emission fixed liquid level gauges or equivalent alternatives during filling of LPG-containing tanks and cylinders, use of LPG low emission connectors, routine leak checks and repairs of LPG transfer and dispensing equipment, and recordkeeping and reporting to demonstrate compliance.

With respect to suppliers and sellers of LPG, HSC §25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

2 The federal RMP program is administered in California through the California Accidental Release Prevention (CalARP) program (HSC §§ 25531 -25543.3 and CCR, Title 19 §§ 2735.1 to 2785.1).

1. Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;

2. Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the California Office of Emergency Services;

3. Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;

4. Procedures to notify the necessary persons who can respond to an emergency within the facility;

5. Details of evacuation plans and procedures;

6. Descriptions of the emergency equipment available in the facility;

7. Identification of local emergency medical assistance; and

8. Training (initial and refresher) programs for employees in:

    a. The safe handling of hazardous materials used by the business;

    b. Methods of working with the local public emergency response agencies;

    c. The use of emergency response resources under control of the handler; and

    d. Other procedures and resources that will increase public safety and prevent or mitigate a release of hazardous materials.

In general, every county or city and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In conjunction with the California Office of Emergency Services, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area.

Lastly, operators who currently transfer and dispense LPG are well aware of the hazardous nature of LPG, including its flammability and receive periodic training for the safe handling of LPG for the following reasons. Facility operators with a dispensing system for LPG are required to comply with operating pressures pursuant to the standards developed by the American Society of Mechanical Engineers (ASME) Pressure Vessel Code, Section 8; NFPA 58 with regard to venting LPG to the atmosphere; and for LPG tanks that are subject to RMP requirements, the operators must obtain permits from, and submit RMPs to the local Certified Unified Program Agency (CUPA) with is typically the city or county fire department. For similar reasons, industrial and commercial customers on the receiving end of LPG deliveries are also well aware of the safety issues associated with LPG. Residential customers, through warning labels on the portable cylinders and on the units to which the portable cylinders connect, are notified of the flammability dangers associated with LPG.

SUBCHAPTER 3.5

HYDROLOGY AND WATER QUALITY

Regulatory Background

Hydrology

Water Demand and Forecasts

Water Supply

Water Conservation

Water Quality

Wastewater Treatment

3.5 HYDROLOGY AND WATER QUALITY

This subchapter describes existing regulatory setting relative to hydrology and water quality, including water supply, water demand, and drought trends within California and the SCAQMD.

3.5.1 Regulatory Background

Water resources are regulated by an overlapping network of local, state, federal and international laws and regulations. As a result, the authority to address a given discharge or activity is not always clear. Therefore, the regulatory background is broken down by the following topics: Water Quality; Regional Water Quality Management; Watershed Management; Wastewater Treatment; Drinking Water Standards; and, local regulations.

3.5.1.1 Water Quality

The principal laws governing water quality in southern California are the federal Clean Water Act (CWA) and the corresponding California law, the Porter-Cologne Water Quality Act. The USEPA is the federal agency responsible for water quality management and administration of the federal CWA. The USEPA has delegated most of the administration of the CWA in California to the California State Water Resources Control Board (SWRCB). The SWRCB was established through the California Porter-Cologne Water Quality Act of 1969, and is the primary State agency responsible for water quality management issues in California. Much of the responsibility for implementation of the SWRCB's policies is delegated to the nine Regional Water Quality Control Boards (RWQCBs).

National Pollutant Discharge Elimination System Permit Program

The CWA §402 established the National Pollutant Discharge Elimination System (NPDES) to regulate discharges into "navigable waters" of the United States. The USEPA authorized the SWRCB to issue NPDES permits in the State of California in 1974. The NPDES permit establishes discharge pollutant thresholds and operational conditions for industrial facilities and wastewater treatment plants. For point source discharges (e.g., wastewater treatment facilities), the RWQCBs prepare specific effluent limitations for constituents of concern such as toxic substances, total suspended solids (TSS), bio-chemical oxygen demand (BOD), and organic compounds. The limitations are based on the Basin Plan objectives and are tailored to the specific receiving waters, allowing some discharges, for instance deep water outfalls in the Pacific Ocean, more flexibility with certain constituents due to the ability of the receiving waters to accommodate the effluent without significant impact.

Non-point source NPDES permits are also required for municipalities and unincorporated communities of populations greater than 100,000 to control urban stormwater runoff. These municipal permits include Storm Water Management Plans (SWMPs). A key part of the SWMP is the development of Best Management Practices (BMPs) to reduce pollutant loads. Certain businesses and projects within the jurisdictions of these municipalities are required to prepare Storm Water Pollution Prevention Plans (SWPPPs) which establish the appropriate BMPs to gain coverage under the municipal permit. On October 29, 1999, the USEPA finalized the Storm Water Phase II rule which requires smaller urban communities with a population less than 100,000 to acquire individual storm water discharge permits.

The Phase II rule also requires construction activities on one to five acres to be permitted for storm water discharges. Individual storm water NPDES permits are required for specific industrial activities and for construction sites greater than five acres. Statewide general storm water NPDES permits have been developed to expedite discharge applications. They include the statewide industrial permit and the statewide construction permit. A prospective applicant may apply for coverage under one of these permits and receive Waste Discharge Requirements (WDRs) from the appropriate RWQCB. WDRs establish the permit conditions for individual dischargers. The Stormwater Phase II Rule automatically designates, as small construction activity under the NPDES stormwater permitting program, all operators of construction site activities that result in a land disturbance of equal to or greater than one and less than five acres. Site activities that disturb less than one acre are also regulated as small construction activity if they are part of a larger common plan of development or sale with a planned disturbance of equal to or greater than one acre and less than five acres, or if they are designated by the NPDES permitting authority. The NPDES permitting authority or USEPA Region may designate construction activities disturbing less than one acre based on the potential for contribution to a violation of a water quality standard or for significant contribution of pollutants to waters of the United States (USEPA, 2005)[1].

Municipal Stormwater and Urban Runoff Discharge Permits

The Municipal Stormwater Permitting Program regulates stormwater discharges from municipal separate storm sewer systems (MS4s). The RWQCB, with oversight by USEPA, administers the MS4 permitting program in the Los Angeles area. The MS4 permits require the municipal discharger (typically, a city or county) to develop and implement a SWMP with the goal of reducing the discharge of pollutants to the maximum extent practicable. The SWMP program specifies what BMPs will be applied to address certain program areas such as public education and outreach, illicit discharge detection and elimination, construction and port-construction, and good housekeeping for municipal operations. MS4 permits also generally include a monitoring program.

CWA §303 – Total Maximum Daily Loads

The CWA §303(d) requires the SWRCB to prepare a list of impaired water bodies in the State and determine total maximum daily loads (TMDLs) for pollutants or other stressors impacting water quality of these impaired water bodies. A TMDL is a quantitative assessment of water quality conditions, contributing sources, and the load reductions or control actions needed to restore and protect bodies of water in order to meet their beneficial uses. All sources of the pollutants that caused each body of water to be included on the list, including point sources and non-point sources, must be identified. The California §303 (d) list was completed in March 1999. On July 25, 2003, USEPA gave final approval to California's 2002 revision of §303 (d) List of Water Quality Limited Segments. A priority schedule has been developed to determine TMDLs for impaired waterways. TMDL projects are in various stages throughout the district for most of the identified impaired water bodies.

[1] Stormwater Phase II Final Rule, Small Construction Program Overview. EPA 833-F-00-013. January, 2000 (revised December 2005), U.S. EPA, 2005.

The RWQCBs will be responsible for ensuring that total discharges do not exceed TMDLs for individual water bodies as well as for entire watersheds.

State Water Quality Certification Program

The RWQCBs also coordinate the State Water Quality Certification program, or CWA §401. Under CWA §401, states have the authority to review any federal permit or license that will result in a discharge or disruption to wetlands and other waters under state jurisdiction to ensure that the actions will be consistent with the state's water quality requirements. This program is most often associated with CWA §404 which obligates the U.S. Army Corps of Engineers to issue permits for the movement of dredge and fill material into and from "waters of the United States".

3.5.1.2 Regional Water Quality Management

Water quality of regional surface water and groundwater resources is affected by point source and non-point source discharges occurring throughout individual watersheds. Regulated point sources, such as wastewater treatment effluent discharges, usually involve a single discharge into receiving waters. Non-point sources involve diffuse and non-specific runoff that enters receiving waters through storm drains or from unimproved natural landscaping. Common non-point sources include urban runoff, agriculture runoff, resource extraction (on-going and historical), and natural drainage. Within the regional Basin Plans, the RWQCBs establish water quality objectives for surface water and groundwater resources and designate beneficial uses for each identified water body.

The Basin Plan (Water Quality Control Plan: Los Regional Basin Plan for the Coastal Watersheds of Los Angeles and Ventura Counties) (LARWQCB, 1994) is designed to preserve and enhance water quality and to protect beneficial uses of regional waters. The Basin Plan designates beneficial uses of surface water and ground water, such as contact recreation or municipal drinking water supply. The Basin Plan also establishes water quality objectives, which are defined as "the allowable limits or levels of water quality constituents or characteristics which are established for the reasonable protection of beneficial uses of water or the prevention of nuisance in a specific area." The Basin Plan specifies objectives for specific constituents, including bioaccumulation, chemical constituents, dissolved oxygen, oil and grease, pesticides, pH, polychlorinated biphenyls, suspended solids, toxicity, and turbidity.

California Water Code, Division 7, Chapter 5.6 established a comprehensive program within the SWRCB to protect the existing and future beneficial uses of California's enclosed bays and estuaries. The Bay Protection and Toxic Cleanup Plan (BPTCP) has provided a new focus on the SWRCB and the RWQCBs' efforts to control pollution of the State's bays and estuaries by establishing a program to identify toxic hot spots and plans for their cleanup. In June 1999, the SWRCB published a list of known toxic hot spots in estuaries, bays, and coastal waters.

Other statewide programs run by the SWRCB to monitor water quality include the California State Mussel Watch Program and the Toxic Substances Monitoring Program.

The Department of Fish and Game collects water and sediment samples for the SWRCB for both of these programs and provides extensive statewide water quality data reports annually. In addition, the RWQCBs conduct water sampling for Water Quality Assessments required by the CWA and for specific priority areas under restoration programs such as the Santa Monica Bay Restoration Program.

3.5.1.3 Watershed Management

In February 1998, the Clean Water Action Plan (CWAP) was established to require states and tribes, with assistance from federal agencies and input from stakeholders and private citizens, to convene and work collaboratively to develop Unified Watershed Assessments (UWA). The CWAP designated watersheds to one of the following categories:

Category I: Watersheds that are candidates for increased restoration because of poor water quality or the poor status of natural resources.

Category II: Watersheds that have good water quality but can still improve.

Category III: Watersheds with sensitive areas on federal, state, or tribal lands that need protection.

Category IV: Watersheds for which there is insufficient information to categorize them.

Targeted watersheds and watershed priorities and activities were identified for each of California's nine RWQCBs. Examples of targeted watersheds include the Santa Monica Bay Restoration Commission and the Malibu Creek Watershed Non-Point Source Pilot Project.

3.5.1.4 Wastewater Treatment

The federal government enacted the CWA to regulate point source water pollutants, particularly municipal sewage and industrial discharges, to waters of the United States through the NPDES permitting program. In addition to establishing a framework for regulating water quality, the CWA authorized a multibillion dollar Clean Water Grant Program, which together with the California Clean Water Bond funding, assisted communities in constructing municipal wastewater treatment facilities. These financing measures made higher levels of wastewater treatment possible for both large and small communities throughout California, significantly improving the quality of receiving waters statewide. Wastewater treatment and water pollution control laws in California are codified in the CWC and CCR, Titles 22 and 23. In addition to federal and state restrictions on wastewater discharges, most incorporated cities in California have adopted local ordinances for wastewater treatment facilities. Local ordinances generally require treatment system designs to be reviewed and approved by the local agency prior to construction. Larger urban areas with elaborate infrastructure in place would generally prefer new developments to hook into the existing system rather than construct new wastewater treatment facilities. Other communities promote individual septic systems to avoid construction of potentially growth accommodating treatment facilities. The RWQCBs generally delegate management responsibilities of septic systems to local jurisdictions. Regulation of wastewater treatment includes the disposal and reuse of biosolids.

3.5.1.5 Drinking Water Standards

The federal Safe Drinking Water Act, enacted in 1974 and implemented by the USEPA, imposes water quality and infrastructure standards for potable water delivery systems nationwide. The primary standards are health-based thresholds established for numerous toxic substances. Secondary standards are recommended thresholds for taste and mineral content. The State of California was first granted primary enforcement responsibility for public water systems under section 1413 of the Safe Drinking Water Act on June 2, 1978 (43 FR 25180, June 9, 1978).

The California Safe Drinking Water Act, enacted in 1976, is codified in Title 22 of the CCR. The California Safe Drinking Water Act provides for the operation of public water systems and imposes various duties and responsibilities for the regulation and control of drinking water in the State of California including enforcing provisions of the federal Safe Drinking Water Act. The California Safe Drinking Water Program was originally implemented by the California Department of Public Health until July 1, 2014 when the program was transferred to the SWRCB via an act of legislation, SB 861. This transfer of authority means that the SWRCB has regulatory and enforcement authority over drinking water standards and water systems under Health and Safety Code §116271.

Potable water supply is managed through the following agencies and water districts: the California Department of Water Resources (DWR), the California Department of Health Services (DHS), the SWRCB, the USEPA, and the U.S. Bureau of Reclamation. Water right applications are processed through the SWRCB for properties claiming riparian rights. The DWR manages the State Water Project (SWP) and compiles planning information on water supply and water demand within the state. Primary drinking water standards are promulgated in the CWA §304 and these standards require states to ensure that potable water retailed to the public meets these standards. Standards for a total of 88 individual constituents, referred to as Maximum Contaminant Levels (MCLs) have been established under the Safe Drinking Water Act as amended in 1986 and 1996. The USEPA may add additional constituents in the future. The MCL is the concentration that is not anticipated to produce adverse health effects after a lifetime of exposure. State primary and secondary drinking water standards are codified in CCR Title 22 §§64431 - 64501. Secondary drinking water standards incorporate non-health risk factors including taste, odor, and appearance. The 1991 Water Recycling Act established water recycling as a priority in California. The Water Recycling Act encourages municipal wastewater treatment districts to implement recycling programs to reduce local water demands. The DHS enforces drinking water standards in California.

3.5.1.6 Local Regulations

In addition to federal and state regulations, cities, counties and water districts may also provide regulatory advisement regarding water resources. Many jurisdictions incorporate policies related to water resources in their municipal codes, development standards, storm water pollution prevention requirements, and other regulations.

3.5.2 Hydrology

3.5.2.1 Water Sources

The DWR divided California into ten hydrologic regions corresponding to the state's major water drainage basins. The hydrologic regions define a river basin drainage area and are used as planning boundaries, which allows consistent tracking of water runoff, and the accounting of surface water and groundwater supplies (DWR, 2010)[2].

The Basin lies within the South Coast Hydrologic Region. The South Coast Hydrologic Region is California's most urbanized and populous region. More than half of the state's population resides in the region (about 19.6 million people or about 54 percent of the state's population), which covers 11,000 square miles or seven percent of the state's total land. The South Coast Hydrologic Region extends from the Pacific Ocean east to the Transverse and Peninsular Ranges, and from the Ventura-Santa Barbara County line south to the international border with Mexico and includes all of Orange County and portions of Ventura, Los Angeles, San Bernardino, Riverside, and San Diego counties (DWR, 2010).

Topographically, most of the South Coast Hydrologic Region is composed of several large, undulating coastal and interior plains. Several prominent mountain ranges comprise its northern and eastern boundaries and include the San Gabriel and San Bernardino mountains. Most of the region's rivers drain into the Pacific Ocean, and many terminate in lagoons or wetland areas that serve as important coastal habitat. Many river segments on the coastal plain, however, have been concrete-lined and in other ways modified for flood control operations (DWR, 2010).

There are 19 major rivers and watersheds in the South Coast Hydrologic Region. Many of these watersheds have densely urbanized lowlands with concrete-lined channels and dams controlling floodflows. The headwaters for many rivers, however, are within coastal mountain ranges and have remained largely undeveloped (DWR, 2010).

The cities of Ventura, Los Angeles, Long Beach, Santa Ana, San Bernardino, and Big Bear Lake are among the many urban areas in this section of the state, which contain moderate-sized mountains, inland valleys, and coastal plains. The Santa Clara, Los Angeles, San Gabriel, and Santa Ana rivers are among the area's hydrologic features. In addition to water sources within the South Coast Hydrologic Region, imported water makes up a major portion of the water used in the Basin. Water is brought into the South Coast Hydrologic Region from three major sources: the Sacramento-San Joaquin Delta (Delta), Colorado River, and Owens Valley/Mono Basin. Most lakes in this area are actually reservoirs, made to hold water coming from the SWP, the Los Angeles Aqueduct (LAA), and the Colorado River Aqueduct (CRA) including Castaic Lake, Lake Mathews, Lake Perris, Silverwood Lake, and Diamond Valley Lake. In addition to holding water, Lake Casitas, Big Bear Lake, and Morena Lake regulate local runoff.

[2] California Water Plan Update, 2009. Integrated Water Management. Bulletin 160-109, DWR, 2010.

3.5.2.2 Surface Water Hydrology

Surface water hydrology refers to surface water systems, including watersheds, floodplains, rivers, streams, lakes and reservoirs, and the inland Salton Sea.

Watersheds

Watersheds refer to areas of land, or basin, in which all waterways drain to one specific outlet, or body of water, such as a river, lake, ocean, or wetland. Watersheds have topographical divisions such as ridges, hills or mountains. All precipitation that falls within a given watershed, or basin, eventually drains into the same body of water (SCAG, 2012)[3]. There are 20 major watersheds within southern California region, all of which are outlined and shaped by the various topographic features of the region. Given the physiographic characteristics of the region, most of the watersheds are located along the Transverse and Peninsular Ranges, and only a small number are in the desert areas (Mojave and Colorado Desert) (SCAG, 2012). Figure 3.5-1 presents a map of the watersheds within the SCAQMD.

Rivers

Because the climate of Southern California is predominantly arid, many of the natural rivers and creeks are intermittent or ephemeral, drying up in the summer or flowing only after periods of precipitation. For example, annual rainfall amounts vary depending on elevation and proximity to the coast. Some waterways such as Ballona Creek and the Los Angeles River maintain a perennial flow due to agricultural irrigation and urban landscape watering (SCAG, 2012). Figure 3.5-2 presents a map of the major rivers within the district.

Major natural streams and rivers in the South Coast Hydrologic Region include the Ventura River, Santa Clara River, Los Angeles River, San Gabriel River, Santa Ana River, San Jacinto River, and upstream portions of the Santa Margarita River.

The Ventura River, located outside of the district, is fed by Lake Casitas on the western border of Ventura County and empties out into the ocean. It is the northern-most river system in Southern California, supporting a large number of sensitive aquatic species. Water quality decreases in the lower reaches due to urban and industrial impacts.

The Santa Clara River starts in Los Angeles County, flows through the center of Ventura County, and remains in a relatively natural state. Threats to water quality include increasing development in floodplain areas, flood control measures such as channeling, erosion, and loss of habitat.

The Los Angeles River is a highly disturbed system due to the flood control features along much of its length. Due to the high urbanization in the area around the Los Angeles River, runoff from industrial and commercial sources as well as illegal dumping contribute to reduce the channel's water quality.

[3] Draft Program Environmental Impact Report for the 2012 – 2035 RTP/SCS. SCAG, 2012.

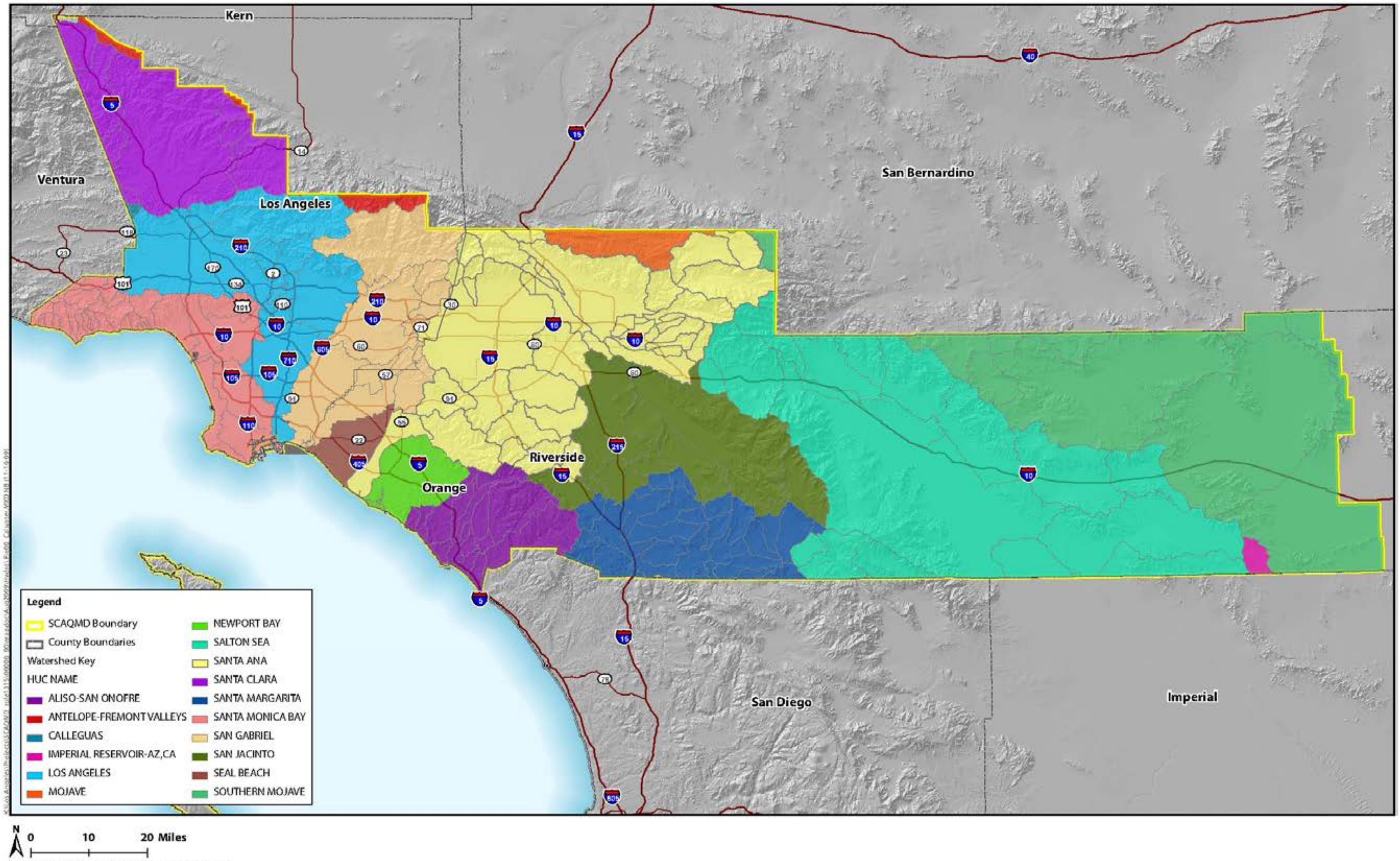

FIGURE 3.5-1
USGS Watersheds within the SCAQMD

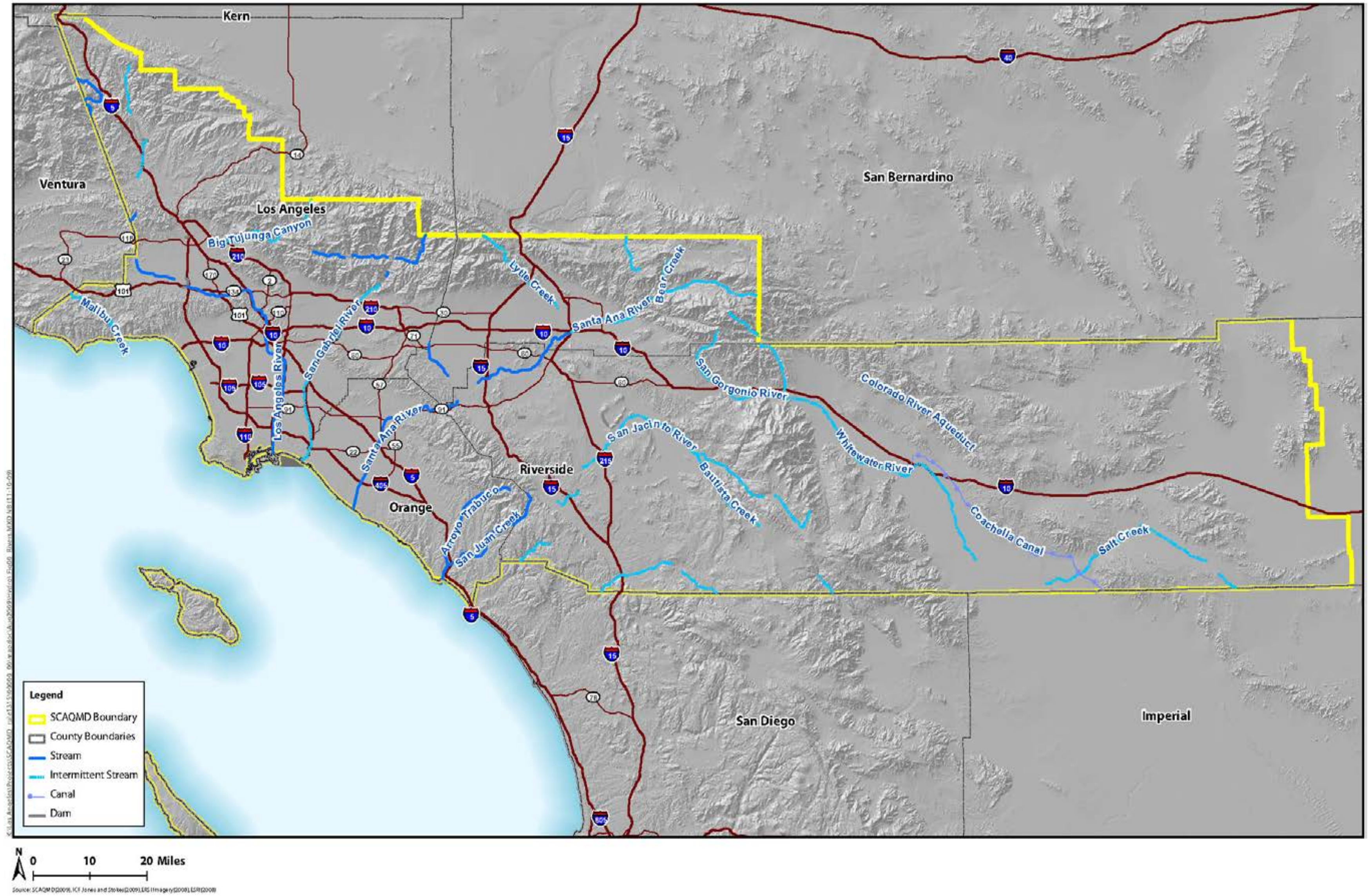

FIGURE 3.5-2
Rivers within the SCAQMD

The San Gabriel River is similarly altered with concrete flood control embankments and impacted by urban runoff.

The Santa Ana River drains the San Bernardino Mountains, cuts through the Santa Ana Mountains, and flows onto the Orange County coastal plain. Recent flood control projects along the river have established reinforced embankments for much of the river's path through urbanized Orange County.

The Santa Margarita River begins in Riverside County, draining portions of the San Jacinto Mountains and flowing to the ocean through northern San Diego County.

Lakes and Reservoirs

Since southern California is a semi-arid region, many of its lakes are drinking water reservoirs, created either through damming of rivers, or manually dug and constructed. Reservoirs also serve as flood control for downstream communities. Some of the most significant lakes, including reservoirs, in the Basin are Big Bear Lake, Lake Arrowhead, Lake Casitas, Castaic Lake, Pyramid Lake, Lake Elsinore, Diamond Valley Lake, and the Salton Sea (SCAG, 2012).

Big Bear Lake is a reservoir in San Bernardino County, in the San Bernardino Mountains. It was created by a granite dam in 1884, which was expanded in 1912, and holds back approximately 73,000 acre-feet[4] of water. The lake has no tributary inflow, and is replenished entirely by snowmelt. It provides water for the community of Big Bear, as well as nearby communities (SCAG, 2012).

Lake Arrowhead is also in San Bernardino County, at the center of an unincorporated community also called Lake Arrowhead. The lake is a man-made reservoir, with a capacity of approximately 48,000 acre-feet of water. In 1922, the dam at Lake Arrowhead was completed, with the intention of turning the area into a resort. It is now used for recreation and as a potable water source for the surrounding community (SCAG, 2012).

Lake Casitas is in Ventura County, and was formed by the Casitas Dam on the Coyote Creek just before it joins the Ventura River. The dam, completed in 1959, holds back nearly 255,000 acre-feet of water. The water is used for recreation, as well as drinking water and irrigation (SCAG, 2012).

Castaic Lake is on the Castaic Creek, and was formed by the completion of the Castaic Dam. The lake is in northwestern Los Angeles County. It is the terminus of the West Branch of the California Aqueduct, and holds over 323,000 acre-feet of water. Much of the water is distributed throughout northern Los Angeles County, though some is released into Castaic Lagoon, which feeds Castaic Creek. The creek is a tributary of the Santa Clara River (SCAG, 2012).

Pyramid Lake is just above Castaic Lake, and water flows from Pyramid into Castaic through a pipeline, generating electricity during the day. At night, when electricity demand

[4] One acre-foot of water is equivalent to 325,851 gallons.

and prices are low, water is pumped back up into Pyramid Lake. Pyramid Lake is on Piru Creek, and holds 180,000 acre-feet of water (SCAG, 2012).

Lake Elsinore is in the City of Lake Elsinore, in Riverside County. While the lake has been dried up and subsequently replenished throughout the last century, it now manages to maintain a consistent water level with outflow piped into the Temescal Canyon Wash (SCAG, 2012).

Diamond Valley Lake is Southern California's newest and largest reservoir. Located in Riverside County, it was a project of Metropolitan Water District (MWD) to expand surface storage capacity in the region. A total of three dams were required to create the lake. Completed in 1999, it was full by 2002, holding 800,000 acre-feet of water, effectively doubling MWD's surface water storage in the region. The lake is connected to the existing water infrastructure of the SWP. The lake is situated at approximately 1,500 feet above sea level, well above most of the users of the lake's water which enables the lake to also provide hydroelectric power, as water flows through the lowest dam (SCAG, 2012).

The Salton Sea is California's largest lake, nearly 400 square miles in size. The lake is over 200 feet below sea level, and has flooded and evaporated many times over, when the Colorado overtops its banks during extreme flood years. This cycle of flooding and evaporation has re-created the Salton Sea several times during the last thousand years and has resulted in high levels of salinity. The lake's most recent formation occurred in 1905 after an irrigation canal was breached and the Colorado River flowed into the basin for 18 months, creating the current lake (SCAG, 2012).

The principle inflow to the Salton Sea is from agricultural drainage, which is high in dissolved salts; approximately four million tons of dissolved salts flow into the Salton Sea every year. The evaporation of the Salton Sea's water, plus the addition of highly saline water from agriculture, has created one of the saltiest bodies of water in the world. The Sea has been a highly successful fishery and is a habitat and migratory stopping and breeding area for 380 different bird species; however, the high, and ever-increasing, salinity of the Sea has resulted in declining fish populations that inhabit it, resulting in declining local and migratory bird that rely on the fish as a food source (SCAG, 2012).

The major surface waters in this section are presented in Table 3.5-1.

TABLE 3.5-1
Major Surface Waters

Wetlands	Rivers, Creeks, and Streams	Lakes and Reservoirs
	Los Angeles Basin	
Ventura River Estuary Santa Clara River Estuary McGrath Lake Ormond Beach Wetlands Mugu Lagoon Trancas Lagoon Topanga Lagoon Los Cerritos Wetlands Ballona Lagoon Los Angeles River Ballona Wetlands	Sespe Creek Piru Creek Ventura River Santa Clara River Los Angeles River Big Tujunga Canyon San Gabriel River	Lake Casitas Lake Piru Pyramid Lake Castaic Lake Bouquet Reservoir Los Angeles Reservoir Chatsworth Reservoir Sepulveda Reservoir Hansen Reservoir San Gabriel Reservoir Morris Reservoir Whittier Narrows Reservoir Santa Fe Reservoir
	Lahontan Basin	
	Mojave river Amargosa River	Silver Lake Silverwood Lake Mojave River Reservoir Lake Arrowhead Soda Lake
	Colorado River Basin	
	Colorado River Whitewater River Alamo River New River	Lake Havasu Gene Wash Reservoir Copper Basin Reservoir Salton Sea Lake Cahuilla
	Santa Ana Basin	
Hellman Ranch Wetlands Anaheim Bay Bolsa Chica Wetlands Huntington Wetlands Santa Ana River Laguna Lakes San Juan Creek Upper Newport Bay San Joaquin Marsh Prado Wetlands	Santa Ana River San Jacinto River	Prado Reservoir Big Bear Lake Lake Perris Lake Matthews Lake Elsinore Vail Lake Lake Skinner Lake Hemet

Source: Draft Program EIR for the 2012-2035 RTP/SCS; SCAG; December 2011, p. 3.13-13.
http://rtpscs.scag.ca.gov/Documents/peir/2012/draft/2012dPEIR_3_13_WaterResources.pdf

3.5.2.3 Groundwater Hydrology

Groundwater is the part of the hydrologic cycle representing underground water sources. Groundwater is present in many forms: in reservoirs, both natural and constructed; in underground streams; and, in the vast movement of water in and through sand, clay, and rock beneath the earth's surface. The place where groundwater comes closest to the surface is called the water table, which in some areas may be very deep, and in others may be right at the surface. Groundwater hydrology is, therefore, connected to surface water hydrology, and cannot be treated as a separate system. One example of how groundwater hydrology can directly impact surface water hydrology is when surface streams are partly filled by groundwater. When that groundwater is pumped out and removed from the system, the stream levels will fall, or even dry up entirely, even though no water was removed from the stream itself (SCAG, 2012).

Groundwater represents most of the Basin's fresh water supply, making up approximately 30 percent of total water use, depending on precipitation levels. Groundwater basins are replenished mainly through infiltration – precipitation soaking into the ground and making its way into the groundwater. Two threats to the function of this system are increases in impervious surface and overdraft (SCAG, 2012).

Impervious surface decreases the area available for groundwater recharge, as precipitation runoff flows off of streets, buildings, and parking lots directly into storm sewers, and straight into either river channels or into the ocean. This prevents the natural recharge of groundwater, effectively removing groundwater from the system without any pumping. Impervious surface also deteriorates the quality of the water, as it moves over streets and buildings, gathering pollutants and trash before entering streams, rivers, and the ocean (SCAG, 2012).

To prevent seawater intrusion in coastal basins in Orange County, recycled water is injected into the ground to form a mound of groundwater between the coast and the main groundwater basin. In Los Angeles County, imported and recycled water is injected to maintain a seawater intrusion barrier (SCAG, 2012).

VOCs and other non-organic contaminants such as perchlorates have created groundwater impairments in industrialized portions of the San Gabriel and San Fernando Valley groundwater basins, where some locations have been declared federal Superfund sites. Subsequently, perchlorate contamination was found in the San Gabriel Valley, and is being removed. The USEPA continues to oversee installation of a groundwater cleanup system, components of which were installed beneath the cities of La Puente and Industry in 2006. Similar problems exist in the Bunker Hills sub-basin of the Upper Santa Ana Valley groundwater basin. Perchlorate contamination has also been found in wells in the cities of Rialto, Colton, and Fontana in San Bernardino County. The presence of contamination in the source water does not necessarily require the closure of a groundwater well. Water systems can implement water treatment accompanied by monthly monitoring for contaminants and/or may blend the problematic water with other "cleaner" water in order to reduce the concentration of the contaminants of concern in the water that is ultimately to be delivered to the end-users (SCAG, 2012). For these reasons, groundwater continues to be used as the predominant source of water supply in these areas (SCAG, 2012).

3.5.3 Water Demand and Forecasts

Estimating total water use in the district is difficult because the boundaries of supplemental water purveyors' service areas bear little relation to the boundaries of the district and there are dozens of individual water retailers within the district. Water demand in California can generally be divided between urban, agricultural, and environmental uses. In southern California, approximately 75 percent of potable water is provided from imported sources. Annual water demand fluctuates in relation to available supplies. During prolonged periods of drought, water demand can be reduced significantly through conservation measures, while in years of above average rainfall demand for imported water usually declines. In 2000, a 'normal' year in terms of annual precipitation, the demand for water in the State was between approximately 82 and 83 million acre-feet. Of this total, southern California accounted for approximately 9.8 million acre-feet (SCAG, 2012).

The increase in California's water demand is due primarily to the increase in population. By employing a multiple future scenario analysis, the California Water Plan Update 2009 (DWR, 2010) provides a growth range for future annual water demand. According to the California Water Plan Update 2009, statewide future annual water demands range from an increase of fewer than 1.5 million acre-feet for the Slow and Strategic Growth scenario, to an increase of about 10 million acre-feet under the Expansive Growth scenario by year 2050. If southern California maintains its share of 12 percent of the state's water demand, the region could be expected to require an additional 500,000 acre-feet by 2030 (SCAG, 2012).

On June 4, 2008, Governor Arnold Schwarzenegger issued Executive Order S-06-08 and declared an official drought for California[5]. Further, California Water Code §71460 et seq. states that a water district may restrict the use of water during any emergency caused by drought, or other threatened or existing water shortage, and may prohibit the use of water during such periods for any purpose other than household uses or such other restricted uses as determined to be necessary. The water district may also prohibit the use of water during such periods for specific uses which it finds to be nonessential. On February 27, 2009, Governor Schwarzenegger proclaimed a state of emergency regarding the drought and the availability and future sustainability of California's water resources[6]. The proclamation directed all state government agencies to utilize their resources, implement a state emergency plan and provide assistance for people, communities and businesses impacted by the drought. The proclamation further requested that all urban water users immediately increase their water conservation activities in an effort to reduce their individual water use by 20 percent.

Following substantial increases in statewide rainfall and mountain snowpack, on March 30, 2011, Governor Jerry Brown officially rescinded Executive Order S-06-08, issued on June 4, 2008 and ended the States of Emergency regarding the drought on June 12, 2008, and on February 27, 2009. The fourth snow survey of the season was conducted by the DWR and found that water content in California's mountain snowpack was 165 percent of the April 1 full season average. At that time, a majority of the state's major reservoirs were also above normal storage levels. Based on this data, DWR estimated it will be able to deliver 70 percent of requested SWP water for 2011.

In 2012, an uptick in water use occurred due to a dry winter and a below-normal snowpack. Statewide hydrologic conditions at the end of June 2012 showed 80 percent of average

[5] Executive Order S-06-08; http://gov.ca.gov/news.php?id=9797
[6] State of Emergency – Water Shortage; http://gov.ca.gov/news.php?id=11557

precipitation to date; runoff at 65 percent of average to date; and reservoir storage at 100 percent of average for the date. However, impacts of drought are typically felt first by those most reliant on annual rainfall such as small water systems lacking a reliable source, rural residents relying on wells in low-yield rock formations, or ranchers engaged in dryland grazing. As of mid-July 2012, 75-percent of California's pasture and range land was reported to be experiencing "poor" or "very poor" water conditions. Over half of the contiguous U.S. is experiencing drought conditions, the largest percentage of the nation experiencing drought conditions in the 12-year record of the U.S. Drought Monitor.

This trend in water shortfall has continued throughout California. In May 2013, Governor Brown issued Executive Order B-21-13 to direct state water officials to expedite the review and processing of voluntary transfers of water and water rights[7]. In December 2013, the Governor formed a Drought Task Force to review expected water allocations, California's preparedness for water scarcity and whether conditions merit a drought declaration. In January 2014, the year 2013 was recorded as the driest year in California's history with California's river and reservoirs below their record lows as well as the snowpack's statewide water content at about 20 percent of normal average. Subsequently, on January 17, 2014, Governor Brown proclaimed a State of Emergency and directed state officials to take all necessary actions to prepare for drought conditions[8]. The proclamation directs state officials to assist farmers and communities that are economically impacted by dry conditions and to ensure the state can respond if there are drinking water shortages. The proclamation also directs state agencies to use less water and hire more firefighters and to initiate a greatly expanded water conservation public awareness campaign. Lastly, the proclamation gives state water officials more flexibility to manage supply throughout California under drought conditions. In response to Governor Brown's proclamation, the DWR took actions to conserve the state's water resources by supplying everyone (e.g., farmers, fish, and people throughout California's cities and towns) with less water[9]. It is important to note that almost all areas served by the SWP have other sources of water, such as groundwater, local reservoirs, and other supplies.

On March 1, 2014, Governor Brown signed a drought relief package [10] which provided $687.4 million to support drought relief, including money for housing and food for workers directly impacted by the drought, bond funds for projects to help local communities more efficiently capture and manage water and funding for securing emergency drinking water supplies for drought-impacted communities. In addition, the legislation increased funding for state and local conservation corps to assist communities with efficiency upgrades and reduce fire fuels in fire risk areas, and includes $1 million for the Save Our Water public awareness campaign to enhance its mission to inform Californians how they can do their part to conserve water. In addition, the legislation required the California Department of Public Health (DPH) to adopt new groundwater replenishment regulations by July 1, 2014, and for the State Water Resources

[7] Governor Brown Issues Executive Order to Streamline Approvals for Water Transfers to Protect California's Farms; http://gov.ca.gov/news.php?id=18048

[8] Governor Brown Declares Drought State of Emergency, January 17, 2014. http://gov.ca.gov/news.php?id=18368

[9] DWR Drops State Water Project Allocation to Zero, Seeks to Preserve Remaining Supplies. DWR, 2014. http://www.water.ca.gov/news/newsreleases/2014/013114pressrelease.pdf

[10] Governor Jerry Brown Signs Drought Relief Package, 2014. http://blogs.sacbee.com/capitolalertlatest/2014/03/jerry-brown-signs-drought-relief-package-in-dry-california.html

Control Board and the DPH to work on additional measures to allow for the use of recycled water and storm water capture for increasing water supply availability. The legislation also made statutory changes to: 1) ensure existing water rights laws are followed; 2) include streamlined authority to enforce water rights laws; and, 3) increase penalties for illegally diverting water during drought conditions. The legislation also provided the California Department of Housing and Community Development with the greatest flexibility to maximize migrant housing units[11].

As of May 29, 2014, the SWRCB issued a curtailment order for 2,648 water agencies and users (e.g., farms, cities and other property owners with so-called "junior" water rights, or those issued by the state after 1914, in the Sacramento River and its tributaries in the Sacramento Valley) to stop pumping water from the American, Feather and Yuba rivers as well as dozens of small streams[12]. Rain and snow from February and March storms have allowed the DWR to increase water contract allocations for SWP deliveries from zero to five percent. Precipitation from these recent storms also eliminated the need for rock barriers to be constructed in the Delta to prevent saltwater intrusion. Additional flexibility in salinity control requirements is being sought as an alternative to the Delta rock barriers that is less harmful for fish, wildlife, and other Delta water users. The Department of Fish and Wildlife (DFW) announced that it will fast-track actions to manage and reduce the drought's impact on fish[13].

On April 25, 2014, Governor Brown proclaimed a second State of Emergency, which waived compliance with CEQA and the state water code for a number of actions, including water transfers, wastewater treatment projects, habitat improvements for winter-run Chinook salmon imperiled by the drought and curtailment of water rights[14]. Furthermore, the order also suspended competitive bidding requirements for drought-related projects undertaken by a number of state agencies, including the DWR, DFW, and DPH. The proclamation closed a loophole that previously allowed homeowner associations to require residents to water lawns, even if the watering conflicted with local water agency rules, and to fine them if they did not comply. On September 16, 2014, Governor Brown signed legislation for California to begin regulating groundwater, a historic change that could lead to restrictions on pumping in some areas to prevent aquifers from dwindling and wells from running dry. The package of three laws put local agencies in charge of managing groundwater supplies, while giving the state new authority to step in when necessary to stabilize declining water tables. The new laws went into effect on January 1, 2015 and target areas where groundwater is being depleted faster than it is being replenished. Local agencies will then have until 2020 or 2022, depending on the severity of the situation, to develop plans for managing groundwater[15].

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[11] Governor Brown, Legislative Leaders Announce Emergency Drought Legislation, 2014. http://gov.ca.gov/news.php?id=18415

[12] California Orders Thousands of Sacramento Valley Water Users To Stop Pumping From Streams, 2014. http://www.sacbee.com/2014/05/29/6441935/state-orders-sacramento-valley.html

[13] Late Storms Allow 5 Percent Allocation to State Water Project Users. DWR, 2014. http://www.water.ca.gov/news/newsreleases/2014/041814.pdf

[14] Governor Brown Orders More Emergency Drought Measures, April 25, 2014. http://www.sacbee.com/2014/04/25/6354618/gov-brown-orders-more-emergency.html

[15] Governor Jerry Brown Signs Landmark Groundwater Legislation, 2014. http://www.desertsun.com/story/news/environment/2014/09/16/california-groundwater-legislation/15725863/

Water districts, in response to the drought, have also taken actions throughout the state such as: 1) asking for voluntary reductions; 2) imposing mandatory restrictions or declaring a local emergency; 3) imposing agricultural rationing; 4) imposing drought rates, surcharges and fines; 5) limiting new development and requiring water efficient landscaping; 6) implementing a conservation campaign; 7) stopping water pumping from various streams; and, 8) adjusting water contract allocations. In addition, water shortages have prompted cities to begin infrastructure improvements to secure future water supplies.

3.5.3.1 Water Suppliers

Southern California is served by many water suppliers, both retail and wholesale with MWD being the largest. Created by the California legislature in 1931, MWD serves the urbanized coastal plain from Ventura in the north to the Mexican border in the south to parts of the rapidly urbanizing counties of San Bernardino and Riverside in the east. MWD provides water to about 90 percent of the urban population of southern California. MWD is comprised of 26 member agencies, with 12 supplying wholesale water to retail agencies and other wholesalers. The remaining 14 agencies are individual cities which directly supply water to their residents. A list of the major water suppliers operating within the district is provided in Table 3.5-2.

MWD's largest water customers are the San Diego County Water Authority (28 percent of MWD's supplies based on 2005-2009 average), the LADWP (15 percent) and the Municipal Water District of Orange County (13 percent). The reliance on MWD's water supplies varies by agency. For example, in recent years, Upper San Gabriel received as little as five percent (in fiscal year 2008/09) of its total water supply from MWD, while Beverly Hills received over 93 percent. However, this relative share of local and imported supplies varies from year to year based on supply and demand conditions (MWD, 2010)[16].

MWD monitors demographics in its service area since water demand is heavily influenced by population size, geographical distribution, variation in precipitation levels, and water conservation practices. In 1990, the population of MWD's service area was approximately 14.8 million people. By 2010, it had reached an estimated 19.1 million, representing about 50 percent of the state's population. Growth has generally been around 200,000 persons per year since 2002. The MWD service area is estimated to reach an estimated population of 21.3 million in 2025, and 22.5 million by 2035 (MWD, 2010). Average per capita water usage generally ranges from 170 to 285 gallons per day (SCAG, 2012).

Actual retail water demands within MWD's service area have increased from 3.1 million acre-feet in 1980 to a projected 4.0 million acre-feet in 2010. This represents an estimated annual increase of about 1.0 percent. A similar gradual increase in estimated total retail water demand is expected between 2010 and 2035 (see Table 3.5-2) (MWD, 2010).

Of the estimated 4.0 million acre-feet of total retail water use in 2010, 93 percent is due to municipal and industrial uses, with agriculture accounting for the other seven percent. The relative share of municipal and industrial water use has increased over time at the expense of

[16] The Regional Urban Water Management Plan. MWD, 2010.

agricultural use which has declined due to urbanization and market factors. By 2035, it is estimated that agriculture will account for only about four percent of total MWD retail demands. It is estimated that total municipal and industrial water use will grow from an annual average of 4.0 million acre-feet in 2010 to 4.7 million acre-feet in 2035. All water demand projections assume normal weather conditions. Future changes in estimated water demand assumes continued water savings due to conservation measures such as water savings resulting from plumbing codes, price effects, and the continuing implementation of utility-funded conservation Best Management Practices (BMPs) (MWD, 2010) (see Table 3.5-2).

TABLE 3.5-2

2015 – 2035 Projected Water Demand

Water District	2015 Demand (MAF)[(a)]	2020 Demand (MAF)	2025 Demand (MAF)	2030 Demand (MAF)	2035 Demand (MAF)
MWD [(b)]	5.45	5.63	5.77	5.93	6.07
LADWP [(c)]	0.615	0.652	0.676	0.701	0.711
Antelope Valley/East Kern Water Agency [(d)]	0.091	0.093	0.095	0.097	N/A [(e)]
Castaic Lake Water Agency [(f)]	0.080	0.088	0.097	0.105	0.114
Coachella Valley Water District [(g)]	0.596	0.624	0.661	0.671	0.689
Crestline-Lake Arrowhead Water Agency [(h)]	0.0015	0.0019	0.0021	0.0023	0.0024
Desert Water Agency [(i)]	0.055	0.059	0.065	0.069	0.073
Palmdale Water Agency [(j)]	0.035	0.040	0.045	0.055	0.060
San Bernardino Valley Municipal [(k)]	0.240	0.256	0.284	0.305	0.324
San Gorgonio Pass Water Agency [(l)]	0.039	0.048	0.060	0.072	0.078
Municipal Water District of Orange County [(m)]	0.526	0.543	0.558	0.564	0.568

(a) MAF = million acre-feet
(b) MWD, 2010
(c) LADWP, 2010
(d) AVEKWA, 2010
(e) Not Available
(f) CLWA, 2011
(g) CVWD, 2011
(h) CLAWA, 2011
(i) DWA, 2011
(j) PWD, 2011
(k) SBVMWD, 2011
(l) SGPWA, 2010
(m) MWDOC, 2011

3.5.3.2 Water Uses

While most land use in the region is urban, other land uses include national forest and a small percentage of irrigated crop acreage (DWR, 1998)[17]. The South Coast Hydrologic Region is the most populous and urbanized region in California. In some portions of the region, water users consume more water than is locally available, which has resulted in an overdraft of groundwater resources and increasing dependence on imported water supplies. The distribution of water uses, however, varies dramatically across the South Coast's

[17] The California Water Plan, DWR, 1998.

planning areas. As a result of recent droughts, South Coast water users have generally become more water efficient. Municipal water agencies are engaged in aggressive water conservation and efficiency programs to reduce per capita water demand. As a result of changes in plumbing codes, energy and water efficiency innovations in appliances, and trends toward more water efficient landscaping practices, urban water demand has become more efficient (DWR, 2010).

For the South Coast region, urban water uses are the largest component of the developed water supply, while agricultural water use is a smaller but significant portion of the total. Imported water supplies and groundwater are the major components of the water supply for this region, with minor supplies from local surface waters and recycled water (DWR, 2010).

Of the total water supply to the region, more than half is either used by native vegetation; evaporates to the atmosphere; provides some of the water for agricultural crops and managed wetlands (effective precipitation); or flows to the Pacific Ocean and salt sinks like saline groundwater aquifers. The remaining portion is distributed among urban and agricultural uses and for diversions to managed wetlands (DWR, 2010).

Residential Water Use

While single-family homes are estimated to account for about 61 percent of the total occupied housing stock in 2010, they are responsible for about 74 percent of total residential water demands. This is consistent with the fact that single-family households are known to use more water than multifamily households (e.g., those residing in duplexes, triplexes, apartment buildings and condo developments) on a per housing-unit basis. This is because single-family households tend to have more persons living in the household; they are likely to have more water-using appliances and fixtures; and they tend to have more landscaping (MWD, 2010).

Non-residential Water Use

Nonresidential water use represents an approximately 25 percent of the total municipal and industrial demands in MWD's service area. This includes water that is used by businesses, services, government, institutions (such as hospitals and schools), and industrial (or manufacturing) establishments. Within the commercial/institutional category, the top water users include schools, hospitals, hotels, amusement parks, colleges, laundries, and restaurants. In southern California, major industrial users include electronics, aircraft, petroleum refining, beverages, food processing, and other industries that use water as a major component of the manufacturing process (MWD, 2010).

Agricultural Water Use

Agricultural water use currently constitutes about seven percent of total regional water demand in MWD’s service area. Agricultural water use accounted for 19 percent of total regional water demand in 1970, 16 percent in 1980, 12 percent in 1990 and five percent in 2008. Part of the reduction seen in 2008 was a 30 percent mandatory reduction in MWD’s Interim Agricultural Water Program deliveries, which continued into 2009 and a 25 percent reduction in 2010 (MWD, 2010). Improved technology has allowed growers to more accurately distribute water to the individual trees. In addition, pressure compensating valves and emitters have enabled growers to irrigate on steep slopes with better precision. Maximizing agricultural irrigation systems lowers the growers' irrigation demands (DWR, 2010).

3.5.4 Water Supply

To meet current and growing demands for water, the South Coast region is leveraging all available water resources: imported water, water transfers, conservation, captured surface water, groundwater, recycled water, and desalination. Given the level of uncertainty about water supply from the Delta and Colorado River, local agencies have emphasized diversification. Local water agencies now utilize a diverse mixture of local and imported sources and water management strategies to adequately meet urban and agricultural demands each year (DWR, 2010).

Water used in MWD's service area comes from both local and imported sources. Local sources include groundwater, surface water, and recycled water. Sources of imported water include the Colorado River, the SWP, and the Owens Valley/Mono Basin. Local sources meet about 45 percent of the water needs in MWD's service area, while imported sources supply the remaining 55 percent (MWD, 2010).

The City of Los Angeles imports water from the eastern Owens Valley/Mono Basin in the Sierra Nevada through the LAA. This water currently meets about seven percent of the region's water needs based on a five-year average from 2005-2009, but is dedicated for use by the city of Los Angeles. Contractually and for planning purposes, MWD treats the LAA as a local supply, although physically its water is imported from outside the region. Other supplies come from local sources, and MWD provides imported water supplies to meet the remaining 47 percent of the region's water needs based on the same five-year period. These imported supplies are received from MWD's CRA and the SWP's California Aqueduct (MWD, 2010).

3.5.4.1 Imported Water Supplies

Water is brought into the South Coast region from three major sources: the Delta, Colorado River, and Owens Valley/Mono Basin. All three are facing water supply cutbacks due to climate change and environmental issues. Although historically imported water served to help the South Coast region grow, it is today relied upon to sustain the existing population and economy. As such, parties in the South Coast region are working closely with other regions, the State, and federal agencies to address the challenges facing these imported supplies. Meanwhile, the South Coast region is working to develop new local supplies to meet the needs of future population and economic growth (DWR, 2010).

Most MWD member agencies and retail water suppliers depend on imported water for a portion of their water supply. For example, Los Angeles and San Diego (the largest and second largest cities in the state) have historically (1995-2004) obtained about 85 percent of their water from imported sources. These imported water requirements are similar to those of other metropolitan areas within the state, such as San Francisco and other cities around the San Francisco Bay (MWD, 2010). A list of major water suppliers operating within the district region is given in Table 3.5-3.

TABLE 3.5-3
Major Water Suppliers in the District Region

Water Agency	Land Area (square miles)	Sources of Water Supply
Antelope Valley and East Kern District	2,300	SWP, groundwater, reclaimed water
Bard Irrigation District (and Yuma Project Reservation Division)	23	Colorado River
Castaic Lake Water Agency	125	SWP and groundwater
Coachella Valley Water District	974	SWP, Colorado River, and local
Crestline Lake Arrowhead	78	SWP
Desert Water Agency	324	SWP, Colorado River, and groundwater
Imperial Irrigation District	1,658	Colorado River
Littlerock Creek Irrigation District	16	SWP, groundwater, and surface water
Metropolitan Water District of Southern California	5,200	SWP, Colorado River
Mojave Water Agency	4,900	SWP and groundwater
Palmdale Water Agency	187	SWP and groundwater
Palo Verde Irrigation District	189	Colorado River
San Bernardino Municipal Water	328	SWP and groundwater
San Gorgonio Pass Water Agency	225	Groundwater

Source: Draft Program EIR for the 2012-2035 RTP/SCS; SCAG; December 2011, p. 3.13-20.
http://rtpscs.scag.ca.gov/Documents/peir/2012/draft/2012dPEIR_3_13_WaterResources.pdf

State Water Project

The SWP is an important source of water for the South Coast region wholesale and retail suppliers. SWP contractors in the region take delivery of and convey the supplies to regional wholesalers and retailers. Contractors in the region are MWD, Castaic Lake Water Agency, San Bernardino Valley Municipal Water District, Littlerock Creek Irrigation District, Palmdale Water District, Crestline – Lake Arrowhead Water Agency, San Gorgonio Pass Water Agency, Desert Water Agency, Coachella Valley Water District, and San Gabriel Valley Municipal Water District (DWR, 2011).

The SWP provides imported water to the MWD service area. Since 2002, SWP deliveries have accounted for as much as 70 percent of its water. In accordance with its contract with the DWR, MWD has a "Table A" allocation of about 1.91 million acre-feet per year under contract from the SWP. Actual deliveries have never reached this amount because they depend on the availability of supplies as determined by DWR. The availability of SWP supplies for delivery through the California Aqueduct over the next 18 years is estimated according to the historical record of hydrologic conditions, existing system capabilities as may be influenced by environmental permits, requests from state water contractors and SWP contract provisions for allocating Table A, Article 21 and other SWP deliveries. The estimates of SWP deliveries to MWD are based on DWR's most recent SWP reliability estimates contained in its SWP Delivery Reliability Report 200716 and the December 2009 draft of the biannual update (MWD, 2010). The amount of precipitation and runoff in the Sacramento and San Joaquin watersheds, system reservoir storage, regulatory requirements, and contractor demands for SWP supplies impact the quantity of water available to MWD (MWD, 2010).

MWD and 28 other public entities have contracts with the State of California for SWP water. These contracts require the state, through its DWR, to use reasonable efforts to develop and maintain the SWP supply. The state has constructed 28 dams and reservoirs, 26 pumping and generation plants, and about 660 miles of aqueducts. More than 25 million California residents benefit from water from the SWP. DWR estimates that with current facilities and regulatory requirements, the project will deliver approximately 2.3 million acre-feet under average hydrology considering impacts attributable to the combined Delta smelt and salmonid species biological opinions (MWD, 2010). Under the water supply contract, DWR is required to use reasonable efforts to maintain and increase the reliability of service to its users.

<u>Colorado River System</u>

Another key imported water supply source for the South Coast region is the Colorado River. California water agencies are entitled to 4.4 million acre-feet annually of Colorado River water. Of this amount, 3.85 million acre-feet are assigned in aggregate to agricultural users; 550,000 acre-feet is MWD's annual entitlement. Until a few years ago, MWD routinely had access to 1.2 million acre-feet annually because Arizona and Nevada had not been using their full entitlement and the Colorado River flow was often adequate enough to yield surplus water (DWR, 2010).

A number of water agencies within California have rights to divert water from the Colorado River. Through the Seven Party Agreement (1931), seven agencies recommended apportionments of California's share of Colorado River water within the state. Table 3.5-4 shows the historic apportionment of each agency, and the priority accorded that apportionment.

The water is delivered to MWD's service area by way of the CRA, which has a capacity of nearly 1,800 cubic feet per second or 1.3 million acre-feet per year. The CRA conveys water 242 miles from its Lake Havasu intake to its terminal reservoir, Lake Mathews, near the city of Riverside. Conveyance losses along the Colorado River Aqueduct of 10 thousand acre-feet per year reduce the amount of Colorado River water received in the coastal plain (MWD, 2010).

TABLE 3.5-4
Priorities of the Seven Party Agreement

Priority	Description	TAF[(a)] Annually
1	Palo Verde Irrigation District – gross area of 104,500 acres of land in the Palo Verde Valley	3,850
2	Yuma Project (Reservation Division) – not exceeding a gross area of 25,000 acres in California	
3(a)	Imperial Irrigation District and land in Imperial and Coachella Valleys[b] to be served by All American Canal	
3(b)	Palo Verde Irrigation District—16,000 acres of land on the Lower Palo Verde Mesa	
4	Metropolitan Water District of Southern California for use on the coastal plain of Southern California[c]	550
Subtotal		**4,400**
5(a)	Metropolitan Water District of Southern California for use on the coastal plain of Southern California	550
5(b)	Metropolitan Water District of Southern California for use on the coastal plain of Southern California[c]	112
6(a)	Imperial Irrigation District and land in Imperial and Coachella Valleys to be served by the All American Canal	300
6(b)	Palo Verde Irrigation District—16,000 acres of land on the Lower Palo Verde Mesa	
7	Agricultural Use in the Colorado River Basin in California	
	Total Prioritized Apportionment	**5,362**

Source: MWD, 2010

(a) TAF = thousand acre-feet.

(b) The Coachella Valley Water District now serves Coachella Valley

(c) In 1946, the City of San Diego, the San Diego County Water Authority, Metropolitan, and the Secretary of the Interior entered into a contract that merged and added the City of San Diego's rights to store and deliver Colorado River water to the rights of MWD. The conditions of that agreement have long since been satisfied.

Since the date of the original contract, several events have occurred that changed the dependable supply that MWD expects from the CRA. The most significant event was the 1964 U.S. Supreme Court decree in Arizona v. California that reduced MWD's dependable supply of Colorado River water to 550 thousand acre-feet per year. The reduction in dependable supply occurred with the commencement of Colorado River water deliveries to the Central Arizona Project (MWD, 2010). The court decision lead to a number of other contracts and agreements on how Colorado River water is divided among various users, the key ones of which are summarized below (MWD, 2010).

- In 1987, MWD entered into a contract with the United States Bureau of Reclamation (USBR) for an additional 180 thousand acre-feet per year of surplus water, and 85 thousand acre-feet per year through a conservation program with the Imperial Irrigation District.
- In 1979, the Present Perfected Rights of certain Indian reservations, cities, and individuals along the Colorado River were quantified.

- In 1999, California's Colorado River Water Use Plan was developed to provide a framework for how California would make the transition from relying on surplus water supplies from the Colorado to living within its normal water supply apportionment. To implement these plans, the Quantification Settlement Agreement (QSA) and several other related agreements were executed. The QSA quantifies the use of water under the third priority of the Seven Party Agreement and allows for implementation of agricultural conservation, land management, and other programs identified in MWD's 1996 Integrated Water Resources Plan (IRP). The QSA has helped California reduce its reliance on Colorado River water above its normal apportionment.
- In October 2004, the Southern Nevada Water Authority and MWD entered into a storage and interstate release agreement. Under this program, Nevada can request that MWD to store unused Nevada apportionment in MWD's service area. The stored water provides flexibility to MWD for blending Colorado River water with SWP water and improves near-term water supply reliability.
- In December 2007, the Secretary of the Interior approved the adoption of specific interim guidelines for reductions in Colorado River water deliveries during declared shortages and coordinated operations of Lake Powell and Lake Mead.
- In May 2006, the MWD and the USBR executed an agreement for a demonstration program that allowed the MWD to leave conserved water in Lake Mead that MWD would otherwise have used in 2006 and 2007. As of January 1, 2010, MWD had nearly 80 thousand acre-feet of conservation water stored in Lake Mead (MWD, 2010).
- The December 2007 federal guidelines provided the Colorado River contractors with the ability to create system efficiency projects. By funding a portion of the reservoir projects at Imperial Dam, an additional 100 thousand acre-feet of water was allocated to MWD.

MWD is undertaking ongoing efforts to maintain and improve the flexibility and quality of its water supply from the Colorado River. MWD recognizes that in the short-term, programs are not yet in place to provide the full targeted amount, even with the programs adopted under the QSA and the opportunities to store conserved water in Lake Mead. The December 2007 federal guidelines concerning the operation of the Colorado River system reservoirs provide more certainty to MWD with respect to the determination of a shortage, normal, or surplus condition for the operation of Lake Mead (MWD, 2010).

<u>Owens Valley Mono Basin (Los Angeles Aqueduct)</u>

High-quality water from the Mono Basin and Owens Valley is delivered through the LAA to the City of Los Angeles. Construction of the original 233-mile aqueduct from the Owens Valley was completed in 1913, with a second aqueduct completed in 1970 to increase capacity. Approximately 480,000 acre-feet per year of water can be delivered to the City of Los Angeles each year; however the amount of water the aqueducts deliver varies from year to year due to fluctuating precipitation in the Sierra Nevada Mountains and mandatory instream flow requirements (DWR, 2010).

Diversion of water from Mono Lake has been reduced following State Water Board Decision 1631. Exportation of water from the Owens Valley is limited by the Inyo-Los Angeles Long Term Water Agreement (and related Memorandum of Understanding) and the Great Basin Air Pollution Control District/City of Los Angeles Memorandum of Understanding (to reduce particulate matter air pollution from the Owens Lake bed) (DWR, 2010).

Over time, environmental considerations have required that the City reallocate approximately one-half of the LAA water supply to environmental mitigation and enhancement projects. As a result, the City of Los Angeles has used approximately 205,800 acre-feet of water supplies for environmental mitigation and enhancement in the Owens Valley and Mono Basin regions in 2010, which is in addition to the almost 107,300 acre-feet per year supplied for agricultural, stockwater, and Native American Reservations. Limiting water deliveries to the City of Los Angeles from the LAA has directly led to increased dependence on imported water supply from MWD. LADWP's purchases of supplemental water from MWD in FY 2008/09 reached an all-time high (LADWP, 2010).

LAA deliveries comprise 39 percent of the total runoff in the eastern Sierra Nevada in an average year. The vast majority of water collected in the eastern Sierra Nevada stays in the Mono Basin, Owens River, and Owens Valley for ecosystem and other uses (LADWP, 2010).

Annual LAA deliveries are dependent on snowfall in the eastern Sierra Nevada. Years with abundant snowpack result in larger quantities of water deliveries from the LAA, and typically lower supplemental water purchases from MWD. Unfortunately, a given year's snowpack cannot be predicted with certainty, and thus, deliveries from the LAA system are subject to significant hydrologic variability (LADWP, 2010).

The impact to LAA water supplies due to varying hydrology in the Mono Basin and Owens Valley is amplified by the requirements to release water for environmental restoration efforts in the eastern Sierra Nevada. Since 1989, when City water exports were significantly reduced to restore the Mono Basin's ecosystem, LAA deliveries from the Mono Basin and Owens Valley have ranged from 108,503 acre-feet in 2008/09 to 466,584 acre-feet in 1995/96. Average LAA deliveries since 1989/90 have been approximately 264,799 acre-feet, about 42 percent of the City of Los Angeles' total water needs (LADWP, 2010).

3.5.4.2 Local Water Supplies

Approximately 50 percent of the region's water supplies come from resources controlled or operated by local water agencies. These resources include water extracted from local groundwater basins, catchment of local surface water, non-MWD imported water supplied through the Los Angeles Aqueduct, and Colorado River water exchanged for MWD supplies (MWD, 2010).

Local sources of water available to the region include surface water, groundwater, and recycled water. Some of the major river systems in southern California have been developed into systems of dams, flood control channels, and percolation ponds for supplying local water and recharging groundwater basins. For example, the San Gabriel and Santa Ana rivers capture over 80 percent of the runoff in their watersheds. The Los Angeles River system, however, is not as efficient in capturing runoff. In its upper reaches, which make up 25 percent of the watershed, most runoff is captured with recharge facilities. In its lower reaches, which comprise the remaining 75 percent of the watershed, the river and its tributaries are lined with concrete, so there are no recharge facilities. The Santa Clara River in Ventura County is outside of MWD's service area, but it replenishes groundwater basins used by water agencies within MWD's service area. Other rivers in MWD's service area, such as the Santa Margarita and San Luis Rey, are essentially natural replenishment systems (MWD, 2010).

3.5.4.3 Surface Water

Local surface capture plays an important water resource role in the South Coast region. More than 75 impound structures are used to capture local runoff for direct use or groundwater recharge, operational or emergency storage for imported supplies, or flood protection. While precipitation contributes most of the annual volume of streamflow to the region’s waterways, urban runoff, wastewater discharges, agricultural tailwater, and surfacing groundwater are the prime sources of surface flow during non-storm periods. The South Coast has experienced a trend of increasing dry weather flows during the past 30 years as the region has developed, due to increased imported water use and associated urban runoff (DWR, 2011).

Surface water runoff augments groundwater and surface water supplies. However, the regional demand far surpasses the potential natural recharge capacity. The arid climate, summer drought, and increased urbanization contribute to the inadequate natural recharge. Urban and agricultural runoff can contain pollutants, which decrease the quality of local water supplies. Local agencies maintain surface reservoir capacity to capture local runoff. The average yield captured from local watersheds is estimated at approximately 90 thousand acre-feet per year. The majority of this supply comes from reservoirs within the service area of the San Diego County Water Authority (MWD, 2010).

3.5.4.4 Groundwater

During the first half of the 20th century, groundwater was an important factor in the expansion of the urban and agricultural sectors in the South Coast region. Today, it remains important for the Santa Clara, MWD Los Angeles and Santa Ana planning areas, but only a small source for San Diego. Court adjudications recharge operations, and other management programs are helping to maintain the supplies available from many of the region’s groundwater basins. Since the 1950s, conjunctive management and groundwater storage has been utilized to increase the reliability of supplies, particularly during droughts. Using the region’s other water resources, groundwater basins are being recharged through spreading basins and injection wells. During water shortages of the imported supplies, more groundwater would be extracted to make up the difference. Water quality issues have impacted the reliability of supplies from some basins. However, major efforts are underway to address the problems and increase supplies for these basins (DWR, 2010).

The groundwater basins that underlie the region provide approximately 86 percent of the local water supply in southern California. The major groundwater basins in the region provide an annual average supply of approximately 1.35 million acre-feet. Most of this water recharges naturally, but approximately 200 thousand acre-feet has historically been replenished each year through MWD imported supplies. By 2025, estimates show that groundwater production will increase to 1.65 million acre-feet (MWD, 2010).

Because the groundwater basins contain a large volume of stored water, it is possible to produce more than the natural recharge of 1.16 million acre-feet and the imported replenishment amount for short periods of time. During a dry year, imported replenishment deliveries can be postponed, but doing so requires that the shortfall be restored in wet years. Similarly, in dry years the level of the groundwater basins can be drawn down, as long as the balance is restored to the natural recharge level by increasing replenishment in wet years. Thus, the groundwater basins can act as a water bank, allowing deposits in wet years and withdrawals in dry years (MWD, 2010).

3.5.4.5 Recycled Water

Local water recycling projects involve further treatment of secondary treated wastewater that would be discharged to the ocean or streams and use it for direct non-potable uses such as landscape and agricultural irrigation, commercial and industrial purpose and for indirect potable uses such as groundwater recharge, seawater intrusion barriers, and surface water augmentation (MWD, 2010).

Within MWD's service area, there are approximately 355,000 acre-feet of planned and permitted uses of recycled water supplies. Actual use is approximately 209,000 acre-feet, which includes golf course, landscape, and cropland irrigation; industrial uses; construction applications; and groundwater recharge, including maintenance of seawater barriers in coastal aquifers. MWD projects the development of 500,000 acre-feet of recycled water supplies (including groundwater recovery) by 2025 (DWR, 2010).

Current average annual recycled water production in the MWD Los Angeles Planning Area is approximately 225 million gallons per day (mgd), which represents approximately 25 percent of the current average annual effluent flows. The Water Replenishment District (WRD) is permitted to recharge up to 50,000 acre-feet per year (45 mgd) of Title 22 recycled water for ground water replenishment of the Montebello Forebay. West Basin Municipal Water District's (WBMWD) Edward Little Water Recycling Facility in El Segundo, which produced approximately 24,500 acre-feet in 2004-2005, recently completed its Phase IV Expansion Project. Approximately 12,500 acre-feet per year of the water produced at this facility is purchased by WRD and injected into the West Coast Barrier. The use of recycled water by LADWP is projected to be approximately 50,000 acre-feet per year by 2019 (DWR, 2010).

Recycled water currently represents approximately four percent of the total water demands in the Santa Ana Planning Area. Eastern Municipal Water District (EMWD) recycles effluent from four wastewater treatment plants. EMWD is also investigating the feasibility of indirect potable reuse through groundwater recharge. The Irvine Ranch Water District

(IRWD) has developed an extensive recycled water treatment and delivery system and will expand capacity through 2013 to meet expected recycled water demand. The Inland Empire Utilities Agency is expanding its water recycling with a goal of meeting 20 percent of their demand or 50,000 acre-feet with recycled water. The Western Water Recycling Facility, owned and operated by Western Municipal Water District, is currently being upgraded and expanded. As infrastructure is further developed, recycled water is projected to surpass surface water as a water supply source for the planning area. The Orange County Water District (OCWD) and Orange County Sanitation District's Groundwater Replenishment System provides 72,000 acre-feet per year of recycled water for groundwater recharge and injection along the seawater barrier (DWR, 2010).

The San Diego Planning Area contains a number of recycled water facilities. In Riverside County, water reclamation facilities include Santa Rosa and Temecula Valley which provide non-potable supplies for local use. Seventeen recycled water tertiary treatment facilities are located within San Diego County. The use of tertiary treated recycled water within the San Diego area is projected to increase from 11,500 acre-feet per year in 2005 to 47,600 acre-feet per year in 2030. In September 2008, the City of San Diego approved funding for a demonstration project that releases advanced treated wastewater to San Vicente Reservoir for blending and subsequent additional treatment prior to redistribution (DWR, 2010).

3.5.4.6 Desalination Plants

In the MWD Los Angeles Planning Area, the Robert W. Goldsworthy Desalter, owned and operated by the WRD, processes approximately 2.75 mgd of brackish groundwater desalination for the purpose of remediating a saline plume located within the West Coast sub-basin and providing a reliable local water source to Torrance (DWR, 2010).

The potential for groundwater banking in the Santa Ana Planning Area is substantial, but the volume of clean water that can be stored may be hindered by high salt concentrations in the existing groundwater. In the Santa Ana watershed, three groundwater desalination plants have been constructed and are producing a total of 24 mgd. The Temescal plant, constructed and operated by the City of Corona, has a capacity of 15 mgd. The Menifee and Perris Desalters, owned and operated by EMWD, are producing seven MGD. The Chino Basin Desalter Authority operates Chino I and Chino II Desalters, which are producing 24 mgd (26,000 acre-feet per year) (DWR, 2010).

The Irvine Desalter Project, a joint groundwater quality restoration project by Irvine Ranch Water District and Orange County Water District, yields 7,700 acre-feet per year of potable drinking water and 3,900 acre-feet per year of non-potable water. The Tustin Seventeenth Street Desalter, owned and operated by the City of Tustin yields approximately 2,100 acre-feet per year. The Arlington Desalter, managed by Western Municipal Water District (WMWD), delivers approximately 6,400 acre-feet of treated groundwater annually to the City of Norco (DWR, 2010).

3.5.5 Water Conservation

In the MWD Los Angeles Planning Area, MWD assists member agencies with implementation of water conservation programs. MWD's conservation programs focus on two main areas: residential programs, and commercial, industrial and institutional programs.

Water conservation continues to be a key factor in water resource management in southern California. For MWD, water-use efficiency is anchored by the adopted Long-Term Conservation Plan (LTCP) (August 2011) and the Local Resources Program (LRP). The LTCP sets goals to help retailers achieve water conservation savings, and at the same time, support technology innovation and transform public perception about the value of water. This plan is market oriented and has both incentive and non-incentive drivers to ultimately change how water is used by southern California consumers. Additionally, the LRP encourages the development and increased use of recycled water through incentives (MWD, 2012)[18].

Outdoor water use is a key focus as watering landscapes and gardens accounts for about half of household water use in MWD's service area. MWD will work with water agencies, landscape equipment manufacturers and other stakeholders to make proper irrigation control more effective and easier to understand. A similar effort will be made to reach out to the region's businesses, industries and agriculture to focus on process improvements that can save both money and water. The final focus will be on residential water use, where MWD will work with water agencies and energy utilities to better promote the choices that consumers have for water-efficient products like faucets, shower heads and high-efficiency clothes washers (MWD, 2012).

MWD's incentive programs aimed at residential, commercial and industrial water users make a key contribution to the region's conservation achievements. The rebate program is credited with water savings of 156,000 acre-feet annually. Funding provided by MWD to member agencies and retail water agencies for locally-administered conservation programs included rebates for turf removal projects, toilet distribution and replacement programs, high-efficiency clothes washer rebate programs and residential water audits (MWD, 2012).

3.5.5.1 Residential Programs

MWD's residential conservation consists of the following programs:

- SoCal Water$mart: A region-wide program to help offset the purchase of water-efficient devices. MWD issued 54,000 rebates for residential fixtures in fiscal year 2008/09, resulting in approximately 2.3 thousand acre-feet of water to be saved annually.
- Save Water, Save A Buck: This program extends rebates to multi-family dwellings. More than 40,000 rebates were issued fiscal year 2008/09 for high-efficiency toilets and washers for multi-family units.
- Member Agency Residential Programs: member and retail agencies also implement local water conservation programs within their respective service areas and receive

[18] Annual Progress Report to the California State Legislature, Metropolitan Water District; February, 2012.

MWD incentives for qualified retrofits and other water-saving actions. Typical projects include toilet replacements, locally administered clothes washer rebate programs, and residential water audits.

MWD has provided incentives on a variety of water efficient devices for the residential sector, including: 1) high-efficiency clothes washers; 2) high-efficiency toilets and ultra-low toilets; 3) irrigation evaluations and residential surveys; 4) rotating nozzles for sprinklers; 5) weather-based irrigation controllers; and, 6) synthetic turf.

3.5.5.2 Commercial, Industrial and Institutional Programs

MWD's commercial industrial and institutional conservation consists of three major programs:

- Save Water, Save-A-Buck Program: The Save-A-Buck program had its largest year in fiscal year 2008/09, providing rebates for approximately 145,000 device retrofits.
- Water Savings Performance Program: This program allows large-scale water users to customize conservation projects and receive incentives for five years of water savings for capital water-use efficiency improvements.
- Member Agency Commercial Programs: Member and retail agencies also implement local commercial water conservation programs using MWD incentives.

A fourth program, the Public Sector Demonstration Program also resulted in water savings. From August 2007 through 2008, MWD offered a one-time program to provide up-front funding to increase water use efficiency in public buildings and landscapes within its service area. Participants included various special districts, school districts, state colleges and universities, municipalities, counties, and other government agencies.

- Enhanced incentives were provided to replace high water-use equipment including toilets, urinals, and irrigation controllers. Program incentives were often sufficient to cover the total cost of the equipment.
- Pay-for-performance incentives were also offered to reduce landscape irrigation water use by at least 10 percent through behavioral modifications.
- MWD' s programs provide rebates for water-saving plumbing fixtures, landscaping equipment, food-service equipment, cleaning equipment, HVAC (heating, ventilating, air conditioning) and medical equipment.

LADWP implements public outreach and school education programs to encourage conservation ethics; seasonal water rates that are approximately 20 percent greater during the summer high use period; and free water conservation kits. In addition, LADWP implemented Mandatory Water Conservation measures in 2009, which are still in effect today. Mandatory Water Conservation restricts outdoor watering and prohibits certain uses of water such as prohibiting customers from hosing down driveways and sidewalks, requiring all leaks to be fixed, and requiring customers to use hoses fitted with shut-off nozzles. As a result of these conservation efforts by LADWP, the water demand for Los Angeles is about the same as it was 25 years ago, despite a population increase of more than one million people. LADWP projects an additional savings of at least 50,000 acre-feet per year by 2030 through additional water conservation programs. The Central Basin Municipal Water District and the WBMWD recently completed water conservation master plans to coordinate and prioritize conservation efforts and identify enforcement protocols (DWR, 2010).

OCWD implements several water use efficiency programs in the Santa Ana Planning Area, including a hotel/motel water conservation program, an annual Children's Water Festival, a Water Heroes program, and water saving tips and tools. Eastern Municipal Water District has a strategic goal to reduce per capita water use and has several programs to replace existing inefficient water devices and encourage water efficiency in new development. Inland Empire Utilities Agency provides multiple rebate programs, including turf removal and water efficient fixtures, and has established the Inland Empire Landscape Alliance to promote the use of water efficiency landscaping by its cities and retail agencies. Western Municipal Water District operates the preeminent water conservation demonstration center in the southland, Landscapes Southern California Style, which has been educating the public about water efficient planting and irrigation for over 15 years (DWR, 2010).

3.5.6 Water Quality

Water quality is a key issue in the South Coast region. Population and economic growth not only affect water demand, but add contamination challenges from increases in wastewater and industrial discharges, urban runoff, agricultural chemical usage, livestock operations, and seawater intrusion. Urban and agricultural runoff can contribute to local surface water sediment from disturbed areas; oil, grease, and toxic chemicals from automobiles; nutrients and pesticides from turf and crop management; viruses and bacteria from failing septic systems and animal waste; road salts; and heavy metals. Three areas that are receiving intense interest are nonpoint source pollution control, salinity management, and emerging contaminants (DWR, 2010).

Three Regional Water Quality Control Boards (Regional Water Boards) have jurisdiction in the South Coast: Los Angeles (Region 4), Santa Ana (Region 8), and San Diego (Region 9). Each Regional Water Board identifies impaired water bodies, establishes priorities for the protection of water quality, issues waste discharge requirements, and takes appropriate enforcement actions within in its jurisdiction. Specific water quality issues within the South Coast include beach closures, contaminated sediments, agricultural discharges, salinity management, and port and harbor discharges. Outside the region, high salinity levels and perchlorate contamination contribute to degraded Colorado River supplies, while seawater intrusion and agricultural drainage threaten SWP supplies (DWR, 2010).

3.5.6.1 Non-Point Source Pollution Control

All non-point source pollution is currently regulated through either the NPDES Permitting Program or the Coastal Non-point Pollution Control Program. The Regional Water Boards issue municipal, industrial, and construction NPDES permits with the goal of reducing or eliminating the discharge of pollutants into the storm water conveyance system. The coastal program requires the USEPA and National Oceanic and Atmospheric Administration to develop and implement enforceable BMPs to control non-point source pollution in coastal waters. Further, the Los Angeles Regional Water Board has adopted conditional waivers for discharges from irrigated agricultural lands, which require farmers to measure and control discharges from their property (DWR, 2010).

South Coast agencies have recently begun to implement Low Impact Development (LID) as a way of improving water quality through sustainable urban runoff management. LID practices include: bioretention and rain gardens, rooftop gardens, vegetated swales and buffers, roof disconnection, rain barrels and cisterns, permeable pavers, soil amendments, impervious surface reduction, and pollution prevention. The Los Angeles and San Diego Regional Water Boards have both incorporated LID language into Standard Urban Storm Water Mitigation Plan requirements for municipal NPDES permits (DWR, 2010).

3.5.6.2 Salinity Management

Surface and groundwater salinity is an ongoing challenge for South Coast water supply agencies. Higher levels of treatment are needed following long-range import of water supplies, as total dissolved solids (TDS) levels are increased during conveyance. Salinity sources in local supplies include concentration from agricultural irrigation, seawater intrusion, discharge of treated wastewater, and recycled water. MWD depends on blending the higher salinity CRA supply at Parker Dam with the lower salinity SWP supply to maintain 500 milligrams per liter (mg/L) TDS or lower. Further, seawater intrusion and agricultural drainage threatens to increase the salinity of SWP supplies. Reduced surface water quality would require additional or upgraded demineralization facilities. Increased salinity also reduces the life of plumbing fixtures and consequently increases replacement costs to customers (DWR, 2010).

Groundwater quality has also been degraded by a long history of groundwater overdrafting and subsequent seawater intrusion. The OCWD, WRD, and Los Angeles County Department of Public Works (LACDPW) operate groundwater injection programs to form hydraulic barriers that protect aquifers from seawater intrusion. Brackish groundwater treatment occurs throughout the Santa Clara and Santa Ana planning areas. Various local agencies have developed salinity and nutrient management plans to reduce salt loading. For example, the Chino Basin Watermaster developed an Optimum Basin Management Plan (Chino Basin Watermaster, 1999) to develop the maximum yield of the basin while protecting water quality. Further development of groundwater recharge programs within the South Coast may exacerbate groundwater salinity and require additional technological advances in desalination (DWR, 2010).

3.5.6.3 Potential Contaminants

Chemical and microbial constituents that have not historically been considered as contaminants are increasingly present in the environment due to municipal, agricultural, and industrial wastewater sources and pathways. Established and emerging contaminants of concern to the region's drinking water supplies include pharmaceuticals and personal care products; disinfection byproducts; those associated with the production of rocket fuel such as perchlorate and nitrosodimethylamine; those that occur naturally such as arsenic; those associated with industrial processes such as hexavalent chromium and MTBE. Wastewater treatment plants are not currently designed to remove these emerging contaminants (DWR, 2010).

3.5.6.4 Planning Area Impairments

Water quality issues within the MWD Los Angeles planning areas (Los Angeles Regional Water Board) stem from a range of sources, including industrial and municipal operations, flow diversion, channelization, introduction of non-native species, sand and gravel operations, natural oil seeps, dredging, spills from ships, transient camps, and illegal dumping. Over time, these practices have resulted in the bioaccumulation of toxic compounds in fish and other aquatic life, instream toxicity, eutrophication, beach closures, and a number of Clean Water Act §303 (d) listings. Water bodies within this planning area have been listed for metals, pesticides, nitrates, trash, salinity, and pH. The Regional Water Board is developing TMDLs for nutrients, pathogens, trash, toxic organic compounds, and metals (DWR, 2010).

Key issues within the Santa Ana Planning Area (Santa Ana Regional Water Board) include: nitrogen/TDS due to flow diversion; nitrogen/TDS associated with past agricultural activities and dairies in the Chino Basin; and pathogen issues from urbanization impacting river and coastal beaches, and past contamination of groundwater basins from perchlorate which is related to rocket fuel disposal and fertilizer use. Water bodies within this planning area typically have nutrient issues, including organic enrichment, low dissolved oxygen, and algal blooms. These are particular problems in Big Bear Lake and Lake Elsinore. Water quality issues also include pathogens, metals, and toxic organic compounds in the lower watershed due to urbanization and agricultural activities. TMDLs have been developed throughout the Santa Ana River and San Jacinto River watersheds for nutrients and pathogens. Along the Newport coast, TMDLs are in place for metals, nutrients, pathogens, pesticides/priority organics, and siltation (DWR, 2010).

The Chino Basin maintains a large concentration of dairy operations along with livestock. Runoff from the dairies contributes nitrates, salts, and microorganisms to both surface water and groundwater. Since 1972, the Santa Ana Regional Water Board has issued waste discharge requirements to the dairies in this basin. Groundwater quality in this basin is integrally related to the surface water quality downstream in the Santa Ana River, which in turn serves as a source for groundwater recharge in Orange County.

3.5.7 Wastewater Treatment

The CWA requires wastewater treatment facilities discharging to waters of the U.S. to provide a minimum level of treatment commonly referred to as tertiary treatment. Modern wastewater treatment facilities consist of staged processes with the specific treatment systems authorized through NPDES permits. Primary treatment generally consists of initial screening and clarifying. Primary clarifiers are large pools where solids in wastewater are allowed to settle out over a period of hours. The clarified water is pumped into secondary clarifiers and the screenings and solids are collected, processed through large digesters to break down organic contents, dried and pressed, and either disposed of in landfills or used for beneficial agricultural applications. Secondary clarifiers repeat the process of the primary clarifiers further, refining the effluent.

Other means of secondary treatment include flocculation (adding chemicals to precipitate solids removal) and aeration (adding oxygen to accelerate breakdown of dissolved constituents). Tertiary treatment may consist of filtration, disinfection, and reverse osmosis technologies. Chemicals are added to the wastewater during the primary and secondary treatment processes to accelerate the removal of solids and to reduce odors. Hydrogen peroxide can be added to reduce odors and ferric chloride can be used to remove solids. Polymers are added to secondary effluent as flocculate. Chlorine is often added to eliminate pathogens during final treatment and sulfur dioxide is often added to remove the residual chlorine. Methane produced by the treatment processes can be used as fuel for the plant's engines and electricity needs. Recycled water must receive a minimum of tertiary treatment in compliance with DHS regulations. Water used to recharge potable groundwater supplies generally receives reverse osmosis and microfiltration prior to reuse. Microfiltration technologies have improved substantially in recent years and have become more affordable. As levels of treatment increase, greater volumes of solids and condensed brines are produced. These by-products of water treatment are disposed of in landfills or discharged to local receiving waters.

Wastewater flows and capacities of major treatment facilities are shown in Table 3.5-5. Much of the urbanized areas of Los Angeles and Orange Counties are serviced by three agencies that operate large publicly owned treatment works (POTWs): the City of Los Angeles Bureau of Sanitation's Hyperion Treatment Plant in El Segundo, the City of Los Angeles Bureau of Sanitation's Terminal Island facility in San Pedro, the Los Angeles County Sanitation District's (LACSD) Joint Water Pollution Control Plant (JWPCP) in Carson, and the Orange County Sanitation District's (OCSD) treatment plants in Huntington Beach and Fountain Valley. These facilities handle more than 70 percent of the wastewater generated in the entire SCAG region (SCAG, 2008).

In addition to these large facilities, medium sized POTWs (greater than 10 mgd) and small treatment plants (less than 10 mgd) service smaller communities in Ventura County, southern Orange County, and in the inland regions. Many of these treatment systems recycle their effluent through local landscape irrigation and groundwater recharge projects. Other treatment systems discharge to local creeks on a seasonal basis, effectively matching the natural conditions of ephemeral and intermittent stream habitats (SCAG, 2012).

Many rural communities utilize individually owned and operated septic tanks rather than centralized treatment plants. The RWQCB generally delegates oversight of septic systems to local authorities. However, water discharge requirements are generally required for multiple-dwelling units and in areas where groundwater is used for drinking water. These water discharge requirements are only issued to properties greater than one acre and are not required for properties greater than five acres in size (SCAG, 2012).

TABLE 3.5-5
Wastewater Flow and Capacity within the SCAQMD

WASTEWATER AGENCY	CURRENT FLOW (MGD)	CAPACITY FLOW (MGD)
Los Angeles County		
Los Angeles County Sanitation Districts		
Joint Water Pollution Control Plant	406.1	590.2
Lancaster Water Reclamation Plant	12.0	16.0
Palmdale Water Reclamation Plant	8.0	15.0
Santa Clarita Water Reclamation Plant	20.0	28.6
City of Los Angeles	554.5	580.0
Las Virgenes Municipal Water District	9.5	16.0
City of Burbank	9.0	9.0
Orange County		
Orange County Sanitation District	221.0	699.0
Irvine Ranch Water District	12.3	23.5
South Orange County Wastewater Authority	26.5	37.7
El Toto Water District	5.4	6.0
Riverside County		
Eastern Municipal Water District	37.3	59.0
City of Riverside	36.0	40.0
Coachella Valley Water District	18.0	31.0
San Bernardino County		
Inland Empire Utilities Agency	60.0	84.0
City of San Bernardino	25.5	33.0
Victor Valley Wastewater Reclamation Authority	12.5	14.5
City of Redlands	6.0	9.5
Total	**1,479.6**	**2,292**

Source: Draft Program EIR for the 2012-2035 RTP/SCS; SCAG; December 2011, p. 3.13-25.
http://rtpscs.scag.ca.gov/Documents/peir/2012/draft/2012dPEIR_3_13_WaterResources.pdf

SUBCHAPTER 3.6

SOLID AND HAZARDOUS WASTE

Regulatory Background

Solid Waste Management

Hazardous Waste Management

3.6 SOLID AND HAZARDOUS WASTE

This subchapter describes existing regulatory setting relative to solid and hazardous waste within the SCAQMD.

3.6.1 Regulatory Background

The Regulatory Background is divided into two sections: Solid Waste and Hazardous Waste.

3.6.1.1 Solid Waste

Federal

The USEPA is the primary federal agency charged with protecting human health and with safeguarding the natural environment: air, water, and land. The USEPA works to develop and enforce regulations that implement environmental laws enacted by Congress. The USEPA is also responsible for researching and setting national standards for a variety of environmental programs, and delegates to states and tribes the responsibility for issuing permits and for monitoring and enforcing compliance. Since 1970, Congress has enacted numerous environmental laws including RCRA, CERCLA, and TSCA. 40 CFR Part 258, Subpart D of RCRA establishes minimum location standards for siting municipal solid waste landfills. Because California laws and regulations governing the approval of solid waste landfills meet the requirements of 40 CFR Part 258, Subpart D, the USEPA delegated the enforcement responsibility to the State of California.

State

With regard to solid non-hazardous wastes, the California Integrated Waste Management Act of 1989 (AB 939), as amended, requires every city and county in the state to prepare a Source Reduction and Recycling Element (SRRE) with its Solid Waste Management Plan that identifies how each jurisdiction will meet the mandatory state waste diversion goals of 25 percent by the year 1995, and 50 percent by the year 2000. SB 2202 mandates that jurisdictions continue 50 percent diversion on and after January 1, 2000. The purpose of AB 939 is to facilitate the reduction, recycling, and re-use of solid waste to the greatest extent possible. Penalties for non-compliance with the goals and timelines set forth within AB 939 can be severe, since the bill imposes fines of up to $10,000 per day on cities and counties not meeting these recycling and planning goals (SCAG, 2012). AB 939 has recognized that landfills and transformation facilities are necessary components of any integrated solid waste management system and an essential component of the waste management hierarchy. AB 939 establishes a hierarchy of waste management practices in the following order and priority: 1) source reduction; 2) recycling and composting; and, 3) environmentally safe transformation/land disposal.

CalRecycle (formerly known as the California Integrated Waste Management Board) has numerous responsibilities in implementing the federal and state regulations summarized above. CalRecycle is the state agency responsible for permitting, enforcing and monitoring solid waste landfills, transfer stations, material recovery facilities (MRFs), and composting facilities within California. Permitted facilities are issued Solid Waste Facility Permits

(SWFPs) by CalRecycle. CalRecycle also certifies and appoints Local Enforcement Agencies (LEAs), county or city agencies which monitor and enforce compliance with the provisions of SWFPs. CalRecycle is also responsible for monitoring implementation of AB 939 by the cities and counties. In addition to these responsibilities, CalRecycle also manages the Recycled-Content Materials Marketing Program to encourage the use of specific recycled-content products in road applications, public works projects and landscaping. These products include recycled aggregate, tire-derived aggregate, rubberized asphalt concrete, and organic materials.

AB 939 requires that each county in the state of California prepare a Countywide Integrated Waste Management Plan (CIWMP). The CIWMP is a countywide planning document that describes the programs to be implemented in unincorporated and incorporated areas of the county that will effectively manage solid waste, and promote and implement the hierarchy of CalRecycle. The CIWMPs consists of a Summary Plan, a SRRE, a Household Hazardous Waste Element, a Non-Disposal Facility Element, and a Countywide Siting Element.

<u>Local</u>

A Summary Plan is a solid waste planning document required by Public Resources Code §41751, in which counties or regional agencies provide an overview of significant waste management problems faced by the jurisdiction, along with specific steps to be taken, independently and in concert with cities within their boundaries (SCAG, 2012).

The SRRE consists of the following components: waste characterization, source reduction, recycling, composting, solid waste facility capacity, education and public information, funding, special waste and integration. Each city and county is required to prepare, adopt, and submit an SRRE to CalRecycle that includes a program for management of solid waste generated within the respective local jurisdiction. The SRREs must include an implementation schedule for the proposed implementation of source reduction, recycling, and composting programs. In addition, the plan identifies the amount of landfill and transformation capacity that will be needed for solid waste which cannot be reduced, recycled, or composted (SCAG, 2012).

Each city and county is required to prepare, adopt and submit to CalRecycle a Household Hazardous Waste Element which identifies a program for the safe collection, recycling, treatment, and disposal of hazardous wastes that are generated by households. The Household Hazardous Waste Element specifies how household hazardous wastes generated within the jurisdiction must be collected, treated, and disposed. An adequate Household Hazardous Waste Element contains the following components: Evaluation of alternatives, program selection, funding, implementation schedule and education and public information (SCAG, 2012).

Each city and county is required to prepare, adopt and submit to CalRecycle, a Non-Disposal Facility Element which includes a description of new facilities and expansion of existing facilities, and all solid waste facility expansions (except disposal and transformation facilities) that recover for reuse at least five percent of the total volume. The Non-Disposal Facility Elements are to be consistent with the implementation of a local jurisdiction's

SRRE. Each jurisdiction must also describe transfer stations located within and outside of the jurisdiction, which recover less than five percent of the material received (SCAG, 2012).

Counties are required to prepare a Countywide Siting Element that describes areas that may be used for developing new disposal facilities. The element also provides an estimate of the total permitted disposal capacity needed for a 15-year period if counties determine that their existing disposal capacity will be exhausted within 15 years or if additional capacity is desired (Public Resources Code §§41700 - 41721.5) (SCAG, 2012).

Each county in the SCAG region has created a CIWMP in accordance with AB 939. Below is a brief description of the recent updates to these plans by county.

Los Angeles County

Los Angeles County is revising its Summary Plan and Siting Element to reflect changes in the county's policies and goals, including promotion of conversion technologies, formation of the Los Angeles Regional Agency, update of countywide jurisdiction assistance programs to meet diversion goals, expansion of existing disposal facilities, and development of additional non-disposal facilities for the use of out-of-county disposal facilities (SCAG, 2012).

Los Angeles County's 2009 Annual Report details the revision process, assesses remaining permitted capacity for the mandated 15-year planning horizon, and outlines seven disposal capacity scenarios, two of which project sufficient capacity to meet future demand through the use of conversion technologies and out-of-county disposal facilities. The Annual Report outlines county solid waste management challenges, including a projected shortfall of permitted disposal capacity in the county, insufficient markets for recovered materials, and steps to promote and develop conversion technologies (SCAG, 2012).

Orange County

Orange County completed the first review of its CIWMP in April 2003. It found sufficient disposal capacity for the 15-year planning horizon, but identified other challenges, including the lack of an operational materials recovery facility in the southern portion of the county, changes in records management to comply with the Disposal Recovery System, and determination of accurate base year data (SCAG, 2012).

In addition to the CIWMP, Orange County's Integrated Waste Management Department has initiated a long-term strategic planning project, the Regional Landfill Options for Orange County, which assesses the solid waste disposal needs of Orange County for the next 40 years. The 2007 Strategic Plan Update for this planning project summarizes progress to maximize capacity at existing landfills, assess alternative technologies and potential out-of-county disposal sites, and expand the Frank R. Bowerman and Olinda Alpha landfills (SCAG, 2012).

Riverside County

Riverside County's CIWMP was approved in 1996, and its 2010 Annual Report found the original plan remained applicable, so no comprehensive update is planned. The Non-Disposal Facility Elements was updated in 2009 and includes plans for four possible solid waste material recovery and transfer facilities; two of which would include household hazardous waste disposal facilities. The Non-Disposal Facility Elements also includes an additional proposed solid waste material recovery facility with capacity for household hazardous waste disposal and one composting facility. The 2008 Five Year Review Report for the CIWMP concluded that the most effective allocation of available resources is to continue to utilize the existing CIWMP as a planning tool augmented by annual reports, and that a revision of the CIWMP is not warranted (SCAG, 2012).

San Bernardino County

San Bernardino County's CIWMP five-year review report was completed in 2007. The report reflects updates to the county's goals and policies, changes to its disposal facilities, and assesses disposal capacity for the mandated 15-year planning horizon. Updated policies include programs to help jurisdictions reach diversion goals, such as additional recycling and composting programs and the development of regional material recovery facilities. The 2007 review found that based on the remaining permitted refuse capacity and projected refuse generation for disposal, the landfills within the county have approximately 26 years of capacity (SCAG, 2012).

Regional Water Quality Control Boards (RWQCB)

New or expanded landfills must submit Reports of Waste Discharge to RWQCBs prior to landfill operations. In conjunction with CalRecycle's approval of SWFPs, RWQCBs issue Waste Discharge Orders which regulate the liner, leachate control and removal, and groundwater monitoring systems at Class III landfills (SCAG, 2012).

South Coast Air Quality Management District (SCAQMD)

The SCAQMD regulates emissions from landfills. Landfill owners/operators must obtain permits to construct and operate landfill flares, cogeneration facilities or other facilities used to combust landfill gas. Owner/operators also are subject to the provisions of SCAQMD Rule 1150.1 - Control of Gaseous Emissions from Landfills. SCAQMD Rule 1150.1 requires the submittal of a compliance plan for implementation of a landfill gas control system, periodic ambient monitoring of surface emissions and the installation of probes to detect the lateral migration of landfill gas (SCAG, 2012).

3.6.1.2 Hazardous Waste

Federal

Hazardous material, as defined in 40 CFR Part 261.20 and 22 CCR Article 9, is required to be disposed of in Class I landfills. California has enacted strict legislation for regulating Class I landfills. The California Health and Safety Code requires Class I landfills to be equipped with liners, a leachate collection and removal system, and a ground water monitoring system.

The HMTA is the federal legislation regulating the trucks that transport hazardous wastes. The primary regulatory authorities are the USDOT, the FHWA, and the FRA. The HMTA requires that carriers report accidental releases of hazardous materials to the USDOT at the earliest practicable moment (49 CFR Part 171, Subpart C).

RCRA gives the USEPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste by "large-quantity generators" (1,000 kilograms/month or more). Under RCRA regulations, hazardous wastes must be tracked from the time of generation to the point of disposal. At a minimum, each generator of hazardous waste must register and obtain a hazardous waste activity identification number. If hazardous wastes are stored for more than 90 days or treated or disposed at a facility, any treatment, storage, or disposal unit must be permitted under RCRA. Additionally, all hazardous waste transporters are required to be permitted and must have an identification number. RCRA allows individual states to develop their own program for the regulation of hazardous waste as long as it is at least as stringent as RCRA. In California, the USEPA has delegated RCRA enforcement to the State of California.

<u>State</u>

Authority for the statewide administration and enforcement of RCRA rests with CalEPA's DTSC. While the DTSC has primary responsibility in the state for regulating the generation, transfer, storage and disposal of hazardous materials, DTSC may further delegate enforcement authority to local jurisdictions. In addition, the DTSC is responsible and/or provides oversight for contamination cleanup, and administers state-wide hazardous waste reduction programs. DTSC operates programs to accomplish the following: 1) deal with the aftermath of improper hazardous waste management by overseeing site cleanups; 2) prevent releases of hazardous waste by ensuring that those who generate, handle, transport, store, and dispose of wastes do so properly; and, 3) evaluate soil, water, and air samples taken at sites. The DTSC conducts annual inspections of hazardous waste facilities. Other inspections can occur on an as-needed basis.

Caltrans sets standards for trucks transporting hazardous wastes in California. The regulations are enforced by the CHP. Trucks transporting hazardous wastes are required to maintain a hazardous waste manifest. The manifest is required to describe the contents of the material within the truck so that wastes can readily be identified in the event of a spill.

The storage of hazardous materials in USTs is regulated by CalEPA's SWRCB, which has delegated authority to the RWQCB and, typically at the local level, to the local fire department.

The Hazardous Waste Control Act (HWCA) created a statewide hazardous waste management program, which is similar to but more stringent than the federal RCRA program. The HWCA is implemented by regulations in CCR Title 26 which describes the following required aspects for the proper management of hazardous waste: identification and classification; generation and transportation; design and permitting of recycling, treatment, storage, and disposal facilities; treatment standards; operation of facilities and staff training; and closure of facilities and liability requirements. These regulations list more than 800 materials that may be hazardous and establish criteria for identifying, packaging, and disposing of such waste. Under the HWCA and CCR Title 26, the generator of hazardous waste must complete a manifest that accompanies the waste from generator to transporter to the ultimate disposal location. Copies of the manifest must be filed with DTSC.

The Unified Program required the administrative consolidation of six hazardous materials and waste programs (Program Elements) under one agency, a CUPA. The Program Elements consolidated under the Unified Program are: Hazardous Waste Generator and On-site Hazardous Waste Treatment Programs (also known as Tiered Permitting); Aboveground Petroleum Storage Tank SPCC; Hazardous Materials Release Response Plans and Inventory Program (also known as the Hazardous Materials Accidental Release Plan); UST Program; and Uniform Fire Code Plans and Inventory Requirements. The Unified Program is intended to provide relief to businesses complying with the overlapping and sometimes conflicting requirements of formerly independently managed programs. The Unified Program is implemented at the local government level by CUPAs. Most CUPAs have been established as a function of a local environmental health or fire department. Some CUPAs have contractual agreements with another local agency, a participating agency, which implements one or more Program Elements in coordination with the CUPA.

The Hazardous Waste Source Reduction and Management Review Act of 1989 requires generators of 12,000 kilograms per year of typical operational hazardous waste to conduct an evaluation of their waste streams every four years and to select and implement viable source reduction alternatives. This Act does not apply to non-typical hazardous waste such as asbestos and polychlorinated biphenyls.

Local

Fire departments and other agencies in the district have a variety of local laws that regulate reporting, storage and handling of hazardous materials and wastes. There are no hazardous waste disposal sites within the jurisdiction of the district. Hazardous waste generated at area facilities, which is not reused on-site, or recycled offsite, is disposed of at a licensed in-state hazardous waste disposal facility. Two such facilities are the Chemical Waste Management (CWM) Kettleman Hills facility in King’s County, and the Clean Harbors facility in Buttonwillow (Kern County). Kettleman Hills has an estimated 15.65 million cubic yard capacity. Buttonwillow receives approximately 960 tons of hazardous waste per day and has an approximate remaining capacity of approximately nine million cubic yards.

3.6.2 Solid Waste Management

Permit requirements, capacity, and surrounding land use are three of the dominant factors limiting the operations and life of landfills. Landfills are permitted by the local enforcement agencies with concurrence from CalRecycle. Local agencies establish the maximum amount of solid waste which can be received by a landfill each day and the operational life of a landfill. Landfills are operated by both public and private entities. Landfills in the district are also subject to requirements of the SCAQMD as they pertain to gas collection systems, dust and nuisance impacts.

Landfills throughout the region typically operate between five and seven days per week. Landfill operators weigh arriving and departing deliveries to determine the quantity of solid waste delivered. At landfills that do not have scales, the landfill operator estimates the quantity of solid waste delivered (e.g., using aerial photography). Landfill disposal fees are determined by local agencies based on the quantity and type of waste delivered.

Over the past thirteen years, disposal tonnage has decreased significantly in the district as the emphasis on recycling to meet the requirements of AB 939 has served to divert tonnage from landfills and conserve landfill capacity. Table 3.6-1 shows data from CalRecycle regarding the number of tons disposed in 2014 (the most recent year for which information is available), for each county within the jurisdiction of the district.

TABLE 3.6-1
Solid Waste Disposed in 2014 by County

County	**Solid Waste Disposed** (tons)
Los Angeles	2,380,812
Orange	2,176,246
Riverside	1,747,442
San Bernardino	808,658
Total	**7,113,158**

Source: 2014 Landfill Summary Tonnage Report, CalRecycle, 2015
Http://www.calrecycle.ca.gov/SWFacilities/Landfills/Tonnages

In viewing facilities on a county-by-county basis, it is important to note that landfills in one county may import waste generated elsewhere. Currently, Orange County offers capacity to out-of-county waste at a “tipping fee” low enough to attract waste from Los Angeles and San Bernardino Counties. In Riverside County, the El Sobrante Landfill is licensed to accept up to 10,000 tons of waste per day from Riverside, Los Angeles, Orange, San Diego, and San Bernardino counties (SCAG, 2012).

Since the enactment of AB 939 in 1989, local governments have implemented recycling programs on a widespread basis, making efforts to meet the 25 percent and 50 percent diversion mandates of AB 939. Statewide, CalRecycle reports that diversion increased from 10 percent in 1989 to 42 percent in 2000 and to 48 percent in 2002. As of 2008, the counties in the SCAG region had met their disposal target rates for waste diversion (SCAG, 2012).

A total of 31 Class III active landfills and two transformation facilities are located within the district with a total capacity of 107,933 tons per day and 3,240 tons per day[1], respectively (see Tables 3.6-2 and 3.6-3). The status of landfills within each county in the district is described in Tables 3.6-6 through 3.6-9.

TABLE 3.6-2

Number and Capacity of Class III Landfills by County

County	Number of Class III Landfills	Capacity (tons per day)
Los Angeles	11	41,749
Orange	3	23,500
Riverside[(a)]	7	24,314
San Bernardino[(a)]	10	18,369
Total	31	107,933

Source: 2012 Annual Report, Los Angeles County Countywide Integrated Waste Management Plan, Appendix E-2 Table 1 (LACDPW, 2013)

(a) Data presented is for the entire county and not limited to the portion of the county within the SCAQMD jurisdiction.

TABLE 3.6-3

Waste Transformation Facilities within the District and Permitted Capacity

Facility	County	Permitted Capacity (tons per day)
Commerce Refuse-to-Energy Facility	Los Angeles	1,000
Southeast Resource Recovery Facility	Los Angeles	2,240
Total		**3,240**

Source: LACDPW, 2013

3.6.2.1 Los Angeles County

The Los Angeles Countywide Siting Element addresses landfill disposal. The purpose of the Countywide Siting Element is to provide a planning mechanism to address the solid waste disposal capacity needed by the 88 cities in Los Angeles County and the unincorporated communities for each year of the 15-year planning period through a combination of existing facilities, expansion of existing facilities, planned facilities, and other strategies.

In 2012, residents and businesses in the county disposed of 8.7 million tons of solid waste at Class III landfills and transformation facilities located in and out of the county (see Tables 3.6-4 and 3.6-5). In addition, the amount of inert waste disposed at permitted inert waste landfills totaled 89,000 tons (LACDPW, 2013).

1 This represents the sum of the permitted capacities of the Southeast Resource Recovery Facility at 2,240 tons per day and the Commerce Refuse-To-Energy Facility at 1,000 tons per day. http://www.calrecycle.ca.gov/SWFacilities/Directory/19-AK-0083/Detail/; http://www.calrecycle.ca.gov/SWFacilities/Directory/19-AA-0506/Detail.

TABLE 3.6-4
Annual Disposal Rate for 2012 (County of Los Angeles)

Facility Type	Disposal Rate (million tons per year)
In-County Class III Landfills	6.239
Transformation Facilities	0.529
Exports to Out-of-County Landfills	1.844
Subtotal MSW[a] Disposed	**8.612**
Permitted Inert Waste Landfills	0.089
Grand Total Disposed	**8.701**

Source: LACDPW, 2013
(a) MSW = Municipal Solid Waste

TABLE 3.6-5
Average Daily Disposal Rate for 2012
(County of Los Angeles)

Facility Type	Disposal Rate (tons per day)
In-County Class III Landfills	19,997
Transformation Facilities	1,695
Exports to Out-of-County Landfills	5,911
Subtotal MSW[a] Disposed	**27,603**
Permitted Inert Waste Landfills	286
Grand Total Disposed	**27,889**

Source: LACDPW, 2013
(a) MSW = Municipal Solid Waste

Waste Generation

The LACDPW conducted a survey requesting landfill operators in the county to provide updates to their estimated remaining disposal capacity based on permitted disposal levels and years of remaining operation. Based on the results of the survey, the total remaining permitted Class III landfill capacity in the county is estimated at 129 million tons (see Table 3.6-6).

TABLE 3.6-6
Los Angeles County Landfill Status as of 2012

Solid Waste Facilities	Total Annual Disposal in 2012	Average Daily Disposal in 2012	Remaining Permitted Capacity		Estimated Year of Closure
	(million tons)	(tons per day)	(million tons)	(million cubic yards)	
Landfills:					
Antelope Valley	0.256	822	16.91	19.95	2042
Burbank	0.033	107	2.95	5.36	2053
Calabasas	0.197	633	5.51	12.34	2028
Chiquita Canyon	0.927	2,971	3.97	6.02	2014
Lancaster	0.213	682	12.27	14.49	2025
Pebbly Beach (Avalon)	0.003	9	0.09	0.10	2028
Puente Hills	2.168	6,950	6.10	11.09	2013
San Clemente	0.000	1	0.04	0.32	2032
Scholl Canyon	0.211	675	3.41	7.01	2028
Sunshine Canyon	2.217	7,107	74.37	96.39	2032
Whittier (Savage Canyon)	0.078	250	3.56	5.93	2025
Azusa[(a)]	0.089	286	64.13	52.13	
Total	**6.393**	**20,491**	**193.32**	**419.13**	**--**
Transformation Facilities:					
Commerce Refuse-to-Energy Facility	0.102	326	466.64	777.73	Not Applicable
Southeast Resource Recovery Facility	0.468	1,499	1,601.96	2,669.94	Not Applicable
Total	**0.570**	**1,825**	**2,068.60**	**3,447.67**	**--**

Source: LACDPW, 2013
(a) Currently only accepting inert waste.

Because of community resistance to the extension of operating permits for existing facilities and to the opening of new landfills in the county, and the dwindling capacity of those landfills with operating permit time left, the exact date on which landfill capacity within the county will be exceeded is uncertain. Landfill remaining life based on Solid Waste Facility

Permits in the county ranges from one year at one facility, to as many as 41 years at another (LACDPW, 2013).

The LACDPW has reviewed the county's ability to meet daily disposal demands under different scenarios (e.g., landfill expansions, alternative technologies, waste-by-rail systems, and reduction/recycling). Under some of the scenarios, the county will have a difficult time meeting future disposal demands. In order to ensure disposal capacity to meet the county needs, jurisdictions in Los Angeles County must continue to pursue all of the following strategies: 1) expand existing landfills; 2) study, promote, and develop conversion technologies; 3) expand transfer and processing infrastructure; 4) develop a waste-by-rail system; and, 5) maximize waste reduction and recycling.

3.6.2.2 Orange County

Orange County currently has three active Class III landfills. They include the following: Prima Deshecha, Frank R. Bowerman and Olinda Alpha. The Prima Deshecha Landfill has a permitted capacity of 4,000 tons per day and an expected closure date of 2067. The Frank R. Bowerman Landfill has a maximum capacity of 11,500 tons per day, and an expected closure date of 2053. The Olinda Alpha Landfill has a permitted capacity of 8,000 tons per day. The current permit expiration of the Olinda Alpha Landfill is 2021 (see Table 3.6-7).

TABLE 3.6-7
Orange County Landfill Status

Landfill	**Total Annual Disposal in 2012** (tons)	**Permitted** (tons/day)	**Remaining Permitted Capacity** (cubic yards)	**Estimated Year of Closure**
Frank R. Bowerman	1,395,735	11,500	205,000,000	2053
Olinda Alpha	1,728,854	8,000	38,578,383	2021
Prima Deshecha	397,536	4,000	87,384,799	2067
Total	**3,522,125**	**23,500**	**330,963,182**	**--**

Source: CalRecycle, 2012

CalRecycle is responsible for ensuring that the county's waste is disposed of in a way that protects public health, safety and the environment. Long-range strategic planning is necessary to ensure that waste generated by the county is safely disposed of and that the county's future disposal needs are met. The Regional Landfill Options for Orange County (RELOOC) program was created for this reason. RELOOC is a 40-year strategic plan being prepared by the CIWMD. The purpose of RELOOC is to evaluate options for solid waste disposal for Orange County citizens. The plan was last updated in September 2007 (RELOOC, 2007)

Orange County cities and unincorporated areas have completed, adopted and implemented a Countywide Integrated Waste Management Plan. Orange County cities and unincorporated areas have residential curbside recycling programs in place.

3.6.2.3 Riverside County

Riverside County has six active sanitary landfills with a total capacity of 23,914 tons per day. Each of these landfills is located within the unincorporated area of the county and is classified as Class III. El Sobrante Landfill is a privately operated landfill open to the public. The six major sites have closure dates projected from 2021 to 2087. The projected date of closure for each landfill is tentative and could be affected by engineering, environmental, and waste flow issues (see Table 3.6-8).

TABLE 3.6-8
Riverside County Landfill Status

Landfill	**Total Annual Disposal in 2010** (tons)	**Permitted** (tons/day)	**Remaining Permitted Capacity** (cubic yards)	**Estimated Year of Closure**
Badlands	516,675	4,000	14,730,025	2024
Blythe	16,256	400	4,159,388	2047
Desert Center	34	60	23,246	2087
El Sobrante	2,025,468	16,054	145,530,000	2045
Lamb Canyon	529,743	3,000	18,955,000	2021
Mecca II	0	0	0	Closed in 2007
Oasis	1,407	400	433,779	2055
Total	**3,089,583**	**23,914**	**183,831,438**	**--**

Source: CalRecycle, 2012

3.6.2.4 San Bernardino County

The County of San Bernardino Solid Waste Management Division (SWMD) is responsible for the operation and management of the County of San Bernardino's solid waste disposal system which consists of five regional landfills and nine transfer stations.

San Bernardino County has six active public landfills within the district’s boundaries with a combined permitted capacity of 18,129 tons per day. Mid-Valley/Fontana Landfill is estimated to reach final capacity by the end of 2033, San Timoteo by 2016, Victorville by 2047, Barstow by 2071, Landers by 2018, California Street by 2042 and Colton Landfill by 2017 (see Table 3.6-9).

TABLE 3.6-9
San Bernardino County Landfill Status

Landfill	**Total Annual Disposal in 2010** (tons)	**Permitted** (tons/day)	**Remaining Permitted Capacity** (cubic yards)	**Estimated Year of Closure**
Mid-Valley/Fontana	535,876	7,500	67,520,000	2033
San Timoteo	123,500	2,000	13,605,488	2043
Victorville Sanitary	249,657	3,000	81,510,000	2047
Barstow Sanitary	64,612	1,500	77,304,902	2071
Landers Sanitary	46,407	1,200	765,098	2018
California Street	79,435	829	6,800,000	2042
Total	**1,099,487**	**16,029**	**247,505,488**	**--**

Source: CalRecycle, 2012

3.6.3 Hazardous Waste Management

Hazardous material, as defined in 40 CFR Part 261.20 and 22 CCR Article 9, is disposed of in Class I landfills. California has enacted strict legislation for regulating Class I landfills. The California Health and Safety Code requires Class I landfills to be equipped with liners, a leachate collection and removal system, and a ground water monitoring system.

There are no hazardous waste disposal sites within the jurisdiction of the SCAQMD. Hazardous waste generated at area facilities, which is not reused on-site, or recycled off-site, is disposed of at a licensed in-state hazardous waste disposal facility. Two such facilities are the CWM Kettleman Hills facility in King's County, and the Clean Harbors facility in Buttonwillow (Kern County).

The Kettleman Hills landfill is operating close to capacity. The DTSC has approved CWM's application to modify its RCRA permit at Kettleman Hills to allow for the expansion of its hazardous waste landfill, Unit B-18, by 14 acres and about 4.9 million cubic yards. CWM has also applied to the USEPA to both renew and modify its existing permits to allow for the expansion of the landfill. The expansion would provide another 12-14 years of life. Kettleman Hills landfill is permitted to dispose of or treat and store hazardous waste from all over California. The facility accepts almost all solid, semi-solid, and liquid hazardous waste. However, Kettleman Hills landfill is not permitted to accept biological agents or infectious wastes, regulated radioactive materials, or compressed gases and explosives.

Buttonwillow receives approximately 900 tons of hazardous waste per day. Buttonwillow has a maximum permitted throughput of 10,500 tons per day. The expectant life of the Buttonwillow Landfill is approximately 25 years.

Hazardous waste also can be transported to permitted facilities outside of California. The nearest out-of-state landfills are U.S. Ecology, Inc., located in Beatty, Nevada; Laidlaw Environmental Services located in Lake Point, Utah; Envirosafe Services, in Grandview, Idaho; CWM in

Carlyss, Louisiana, and Waste Control Specialists in Andrews, Texas. Incineration is provided at Laidlaw Environmental Services, Inc., located in Deer Park, Texas.

In 2013, less than 2.30 million tons of hazardous waste were generated in the four counties that comprise the district, and about two million tons of hazardous waste were generated in California (see Table 3.6-10). These amounts are increased from the totals of 2011 by approximately 99, 46, 81, and 2 percent respectively. The most common types of hazardous waste generated in the district include waste oil, inorganic solid waste, contaminated soils, organic solids, asbestos-containing waste, and unspecified oil-containing wastes. Because of the population and economic base in southern California, a large portion of hazardous waste is generated within the district. Not all wastes are disposed of in a hazardous waste facility or incinerator. Many of the wastes generated, including waste oil, are recycled within the Basin.

TABLE 3.6-10
Hazardous Waste Generation by County – 2013
(tons per year)

Waste Name	Los Angeles	Orange	Riverside	San Bernardino	Four County Total	Statewide Total
Waste & Mixed Oil	237,814	11,596	6,177	37,960	293,547	511,503
Inorganic Solid Waste	78,875	23,260	1,611	13,801	117,547	376,237
Contaminated Soils From Site Clean-up	1,401,202	10,941	5,260	8,370	1,425,773	2,016,359
Organic Solids	78,875	5,132	2,741	11,325	98,073	136,292
Asbestos Waste	35,314	9,964	4,631	5,880	55,789	97,503
Unspecified Oil-Containing Waste	29,135	4,172	1,646	34,418	69,371	115,504
Unspecified Solvent Mixture	19,468	1,287	340	601	21,696	50,226
Aqueous Solutions w/Organic Residues	20,773	2,710	846	5,055	29,384	61,862
Polychlorinated Biphenyls	18,032	7,521	82	835	26,470	38,243
Polymeric Resin Waste	124	15,773	8	31	15,936	16,032
Household Waste	3,086	2,172	376	501	6,135	13,292
Unspecified Aqueous Solution	15,664	1,716	746	2,437	20,563	34,783
Unspecified Organic Liquid Mixture	17,404	1,575	440	934	20,353	23,640
Aqueous Solution with Metals[a]	2,758	707	5	21	3,491	4,896
Unspecified Sludge Waste	1,253	244	1,234	327	3,058	17,200
Alkaline Solution (pH >= 12.5) W/O Metals	2309	323	688	98	3,418	8,733
Liquids w/Arsenic >= 500 mg/l[b]	239	--	46	0.01	285	223
Blank/Unknown	6,301	76,565	229	1,720	84,815	264,633
Totals	**1,968,626**	**164,728**	**27,106**	**124,134**	**2,295,704**	**3,787,161**

Source: DTSC, 2014
(--) Not on list of top twenty waste totals generated in the county.
(a) Smaller than restricted levels.
(b) The data for this waste code is as reported in the California Hazardous Waste Tracking System database; however, one or more of the data entries for this waste category appear to be in error.

SUBCHAPTER 3.7

TRANSPORTATION AND TRAFFIC

Transportation Regulatory Framework

Existing Traffic Setting

3.7 TRANSPORTATION AND TRAFFIC

The proposed project may have direct or indirect traffic impacts associated with implementation of control strategies proposed by the Port(s). Traffic concerns are related to modifications to the existing transportation system that may generate significant impacts. This subchapter describes the current transportation system in southern California.

3.7.1 Transportation Regulatory Framework

3.7.1.1 Federal Regulatory Framework

Transportation Equity Act for the 21st Century

The Transportation Equity Act for the 21st Century (TEA-21), signed into law in 1998, provides the regulatory framework at the federal level for transportation planning in urban areas. This legislation requires that Metropolitan Planning Organizations (MPO) prepare long-range transportation plans. In federally designated air quality nonattainment and maintenance areas, the long-range transportation plan is to be updated every three years. The state of California has additional regulations for the preparation of long-range transportation plans. Otherwise, because transportation and traffic are generally local activities, there are no other federal regulations that are pertinent to the proposed project.

3.7.1.2 State Regulatory Framework

California Department of Transportation (Caltrans)

Traffic management in the state of California is guided by policies and standards set at the state level, primarily by the California Department of Transportation (Caltrans). Caltrans is an executive department within California responsible for highway, bridge, and rail transportation planning, construction, and maintenance. Its purpose is to improve mobility across the state. Caltrans manages the state highway system (which includes the California Freeway and Expressway System) and is actively involved with public transportation systems throughout the state. For administrative purposes, Caltrans has divided the state of California into 12 districts supervised by district offices. In southern California, District 7 covers Los Angeles and Ventura counties, District 12 covers Orange County, and District 8 covers Riverside and San Bernardino counties.

Caltrans, in conjunction with the California Highway Patrol (CHP), has created Transportation Management Centers (TMCs) to rapidly detect and respond to roadway incidents, while managing the resulting traffic congestion. With the help of intelligent transportation system technologies, such as electronic sensors in the pavement, freeway call boxes, video cameras, ramp meter sensors, earthquake monitors, motorist cellular calls, and commercial traffic reports, as well as Caltrans highway crews, 911 calls and officers on patrol, each TMC provides coordinated transportation management for general commutes, special events and incidents affecting traffic. The TMCs are operated within each Caltrans district.

<u>CARB Truck and Bus Regulation</u>

CARB adopted the Truck and Bus Regulation in December 2008 to reduce PM and NOx emissions from existing diesel vehicles operating throughout California. This regulation applies to nearly all diesel fueled trucks and buses with a gross vehicle weight rating (GVWR) greater than 14,000 pounds that are privately or federally owned and for privately and publicly owned school buses. This regulation requires all trucks and buses to have 2010 model year engines by 2023. As of January 1, 2012, heavier trucks would be required to meet the engine model year phase-in schedule and fleets that comply with the schedule would install the best available PM filter on 1996 model year and newer engines and would replace the vehicle eight years later. Trucks with 1995 model year and older engines would be replaced starting 2015. Replacements with a 2010 model year or newer engines meet the final requirements, but fleets could also replace with used trucks that would have a future compliance date on the schedule. In addition, fleets that report and use the phase-in option for heavier trucks, could take advantage of credits to delay requirements for other heavier trucks in the fleet until 2017 for the following:

- PM filters installed before July 2011;
- Early purchase of cleaner engines before 2012 (originally equipped with PM filters) ;
- Reducing the number of trucks since 2006; and,
- Adding fuel-efficient hybrids or alternative fueled engines to the fleet.

As part of the analysis of the phase-in option, CARB's projections at the time the Truck and Bus Regulation was adopted estimated the number of plug-in hybrid vehicles, battery electric vehicles, and fuel cell vehicles that will be driving on district roadways will substantially increase between year 2013 and year 2025, as shown in Table 3.7-1.

TABLE 3.7-1

CARB's Projected Populations of Near-Zero and Zero Emission Vehicles in the SCAQMD

Year	Plug-In Hybrid Vehicle (PHEV)	Battery Electric Vehicle (BEV)	Fuel Cell Vehicle (FCV)	Total
2013	15,088	7,196	771	23,055
2014	22,626	7,476	1,058	31,160
2015	33,217	9,725	2,204	45,146
2016	44,442	12,114	3,420	59,976
2017	55,708	14,496	4,635	74,839
2018	79,608	19,778	5,825	105,211
2019	108,615	30,754	8,398	147,767
2020	142,290	46,129	12,837	201,256
2021	178,827	64,365	19,049	262,241
2022	219,896	84,998	27,745	332,639
2023	265,310	108,206	38,839	412,355
2024	314,923	132,900	52,784	500,607
2025	368,087	157,414	69,896	595,397

Source: Communication with ARB Staff, Mobile Source Division, August 14, 2012.

3.7.1.3 Regional Regulatory Framework – Congestion Management Programs (CMPs)

In order to meet federal certification requirements, county Congestion Management Agencies (CMAs) have worked together to develop a congestion management process for the southern California area. In southern California, the Congestion Management System (CMS) is comprised of the combined activities of the Regional Transportation Plan (RTP), the CMP and the Regional Transportation Improvement Program (RTIP).

Under California law, CMPs are prepared and maintained by the CMAs. The Los Angeles County Metropolitan Transportation Authority (Metro), Orange County Transportation Authority (OCTA), Riverside County Transportation Commission (RCTC), and San Bernardino Associated Governments (SANBAG) are the designated CMAs of each county and are subject to State requirements.

In addition to the SCAG RTP and RTIP, the key elements of the federal Congestion Management Process are addressed through the counties' CMPs. Because the magnitude of congestion and degree of urbanization differ among the counties, each CMP differs in form and local procedure. By state law, all CMPs are required to perform the monitoring and management functions summarized in the following bullet points, which also fulfill the federal CMP requirements:

- Highway Performance: The monitoring of the performance of an identified highway system as conducted by each CMA allows each county to track how their system, and its individual components, is performing against established standards, and how performance changes over time.
- Multi-Modal Performance: Each CMP contains an element to evaluate the performance of other transportation modes including transit.
- Transportation Demand Management: Each CMP contains a Transportation Demand Management (TDM) component geared at reducing travel demand and promoting alternative transportation methods.
- Land Use Programs and Analysis: Each CMP incorporates a program for analyzing the effects of local land use decisions on the regional transportation system.
- Capital Improvement Program: Using data and performance measures developed through the activities identified above, each CMP develops a Capital Improvement Program (CIP) which is the first step in developing the RTIP. Under state law, projects funded through the RTIP must first be contained in the county CIP.
- Deficiency Planning: The CMP contains provisions for "deficiency plans" to address unacceptable levels of congestion. Deficiency plans can be developed for specific problem areas or on a system-wide basis. Projects implemented through the deficiency plans must, by statute, have both mobility and air quality benefits. In many cases, the deficiency plans capture the benefits of transportation improvements that occur outside the county TIPs and RTIP such as non-traditional strategies and/or non-regionally significant projects.

- The regional transportation planning process and the county congestion management process should be compatible with one another. To ensure consistency, SCAG and the CMAs have developed the Regional Consistency and Compatibility Criteria for CMPs. Information on the CMP activities and resulting data are updated on a biennial basis by each CMA and supplied to SCAG and air quality management districts.

3.7.1.4 Local Regulatory Framework – General Plans

Under state planning law, every city and county must adopt a General Plan that sets forth the goals, policies and implementation measures for future growth and development. General plans must include seven elements, among which is a circulation element. The circulation element must describe the existing transportation network and describes all planned future transportation improvements. Many local transportation elements, or their implementing ordinances, include criteria for measuring the functionality of current and future roadways, typically through a level-of-service (LOS) measurement system, a volume-to-capacity (VC) ratio, or other such approaches.

3.7.1.5 Transportation-related Policies in California

<u>METRANS Transportation Center</u>

The METRANS Transportation Center, a joint partnership between the University of Southern California and California State University Long Beach, is a University Transportation Center that was established in 1998 under the TEA-21 as a policy advocacy organization to foster independent, high quality research to solve the nation's transportation problems. The mission of METRANS is to "solve transportation problems of large metropolitan regions through interdisciplinary research, education and outreach." METRANS conducts research in several areas relating to transportation, including safety, security, and vulnerability. In addition to performing research, one of the primary goals of METRANS is to disseminate the research information, as well as, best practices and technology to the professional community.

<u>Intelligent Transportation System</u>

One way to incorporate safety and security into transportation planning is through greater collaboration between transportation planning and operations. An Intelligent Transportation System (ITS) is one method of establishing this collaborative relationship by creating an ITS Architecture. An ITS Architecture is a framework for ensuring institutional agreement and technical integration of technologies for the implementation of projects or groups of projects under an ITS strategy. ITS projects were originally designed to increase transportation efficiency and to enhance the safety, security and emergency response capabilities of the region.

Because the successful operation of ITS projects usually depends on multiple agencies and the systems they operate, a framework made up of multiple ITS Architectures, has been developed at the state, regional, and local levels to help achieve cooperation, coordination and communication amongst participants in the most cost-effective manner. For example, at the state level, the California ITS Architecture and System Plan addresses those services that are managed at a state level or are interregional in nature. Project sponsors are responsible for ensuring that their projects maintain consistency with the regional architectures, regardless of which architecture applies, as a requirement for federally funded projects.

At the regional level, a Regional ITS Architecture provides a framework to address multi-county issues including those projects, programs, and services that require connectivity across county boundaries or are deployed at a multi-county level for ITS planning that promotes interoperability and communication across jurisdictional boundaries. Projects developed under a regional framework extend the usefulness of any single project by making information easily accessible for operators and users of the system. For example, the southern California ITS Regional Architecture is a Regional ITS Architecture that was developed specifically for all counties in the southern California area in order to document the ITS Architecture covering the region.

Local components to the ITS Architecture exist for Los Angeles County, Orange County, Riverside County, and San Bernardino County.

3.7.2 Existing Traffic Setting

The southern California transportation system is a complex intermodal network designed to carry both people and goods that consists of roads, highways, public transit, paratransit, bus, rail, airports, seaports, and intermodal terminals. The regional highway system consists of an interconnected network of local streets, arterial streets, freeways, carpool lanes and toll roads. This highway network allows for the operation of private automobiles, carpools, private and public buses, and trucks. Active transportation modes, such as bicycles and pedestrians share many of these facilities. The regional public transit system includes local shuttles, municipal and area-wide public bus operations, rail transit operations, regional commuter rail services, and interregional passenger rail service. The freight railroad network includes an extensive system of private railroads and several publicly owned freight rail lines serving industrial cargo and goods. The airport system consists of commercial, general, and military aviation facilities serving passenger, freight, business, recreational, and defense needs. The region's seaports support substantial international and interregional freight movement and tourist travel. Intermodal terminals consisting of freight processing facilities, which transfer, store, and distribute goods. The transportation system supports the region's economic needs, as well as the demand for personal travel.

Transit use is growing in southern California. As of 2009, transit agencies in the southern California area reported 747.3 million boardings (SCAG, 2012). This represents growth of nearly 20 percent in the decades between 2000 and 2010, but only four percent growth in per capita trips due to population growth. Metrolink and Metro Rail (Los Angeles County) have seen ridership growth of six percent to eight percent per year.

3.7.2.1 Transportation Planning

Numerous agencies are responsible for transportation planning and investment decisions within the southern California area. SCAG helps integrate the transportation-planning activities in the region to ensure a balanced, multimodal plan that meets regional as well as county, subregional, and local goals.

Table 3.7-2 identifies local and state agencies that participate in the development of RTP. Seven major entities and agencies are involved including SCAG as the designated Metropolitan Planning Organization, the County Transportation Commissions, Subregional Councils of Governments, local and county governments, transit and transportation owners, operators and implementing agencies, resource/regulating agencies and other private non-profit organizations, interest groups and tribal nations.

TABLE 3.7-2

Stakeholders in Transportation Planning in the Southern California Area

COUNTY TRANSPORTATION COMMISSIONS
Los Angeles County Metropolitan Transportation Authority (Metro)
Orange County Transportation Authority (OCTA)
Riverside County Transportation Commission (RCTC)
SUBREGIONAL COUNCILS OF GOVERNMENTS
Southern California Association of Governments (SCAG)
San Bernardino Associated Governments (SANBAG)
City of Los Angeles
North Los Angeles County
Orange County Council of Governments
San Fernando Council of Governments
San Gabriel Valley Council of Governments
Western Riverside County Council of Governments
Westside Cities Council of Governments
OTHERS
Caltrans
Airport Authorities
Port Authorities
Transportation Corridor Agencies
Transit/Rail Operators

Each of the four counties within the jurisdiction of the SCAQMD has a Transportation Commission or Authority. These agencies are charged with countywide transportation planning activities, allocation of locally generated transportation revenues, and in some cases operation of transit services. In addition, there are many subregional Councils of Government within the southern California area. A Council of Governments is a group of cities and communities geographically clustered and sometimes comprises an entire county (e.g., Orange County), which work together to identify, prioritize, and seek transportation funding for needed investments in their respective service areas.

3.7.2.2 Existing Circulation System

Commute Patterns and Travel Characteristics

The existing transportation network serving the southern California area supports the movement of people and goods. On a typical weekday in the four-county region, including those portions of the county not located within the jurisdiction of the SCAQMD, the transportation network supports approximately 420 million vehicle miles of travel (VMT) and 12 million vehicle hours of travel (VHT). Of these totals, over half occur in Los Angeles County and less in Orange County, San Bernardino County, and Riverside County, respectively. Detailed summaries of the existing VMT and VHT for these areas are presented in Table 3.7-3 and Table 3.7-4, respectively.

TABLE 3.7-3
Summary of Existing Daily Vehicle Miles

County	Vehicle Miles of Travel (VMT)					
	AM Peak Period		PM Peak Period		Daily	
	Miles	% of Region	Miles	% of Region	Miles	% of Region
Los Angeles	46,321,000	54%	74,635,000	54%	224,312,000	54%
Orange	15,589,000	18%	24,793,000	18%	75,224,000	18%
Riverside	12,099,000	14%	18,817,000	14%	60,494,000	14%
San Bernardino	12,242,000	14%	18,944,000	14%	61,010,000	14%
Total	**86,251,000**	**100%**	**137,189,000**	**100%**	**420,980,000**	**100%**

Source: SCAG 2012. Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

TABLE 3.7-4
Summary of Existing Daily Vehicle Hours of Travel

County	Vehicle Hours of Travel (VHT)					
	AM Peak Period		PM Peak Period		Daily	
	Hours	% of Region	Hours	% of Region	Hours	% of Region
Los Angeles	1,627,000	60%	3,181,000	62%	7,428,000	60%
Orange	474,000	17%	879,000	17%	2,171,000	17%
Riverside	320,000	12%	542,000	11%	1,469,000	12%
San Bernardino	307,000	11%	512,000	10%	1,416,000	11%
Total	**2,728,000**	**100%**	**5,114,000**	**100%**	**12,484,000**	**100%**

Source: SCAG, 2012. Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

Much of the existing travel in the southern California area takes place during periods of congestion, particularly during the morning (e.g., from 6:00 a.m.to 9:00 a.m.) and evening peak periods (e.g., from 3:00 p.m. to 7:00 p.m.). Congestion can be quantified as the amount of travel that takes place in delay (vehicle hours of delay or VHD), and alternately, as the percentage of all travel time that occurs in delay (defined as the travel time spent on the highway due to congestion, which is the difference between VHT at free-flow speeds and VHT at congested speeds). Table 3.7-5 presents the existing travel delays and percent of regional VHT in delay by county on freeways and arterials. As shown in Table 3.7-5, regional travel time in delay represents approximately 25 percent of all daily, 30 percent of all AM peak period, and 38 percent of all PM peak period travel times. Also as shown in Table 3.7-5, a substantial portion of AM peak period travel in each county takes place in delay, ranging from a low of 21 percent in San Bernardino County to a high of 34 percent in Los Angeles County.

TABLE 3.7-5
Summary of Existing Vehicle Hours of Delay

County	Vehicle Hours of Delay			% of Travel in Delay		
	AM Peak Period	AM Peak Period	Daily	AM Peak Period	AM Peak Period	Daily
Los Angeles	554,000	1,387,000	2,204,000	34%	44%	4%
Orange	128,000	313,000	493,000	27%	36%	23%
Riverside	78,000	158,000	263,000	24%	29%	18%
San Bernardino	64,000	125,000	205,000	21%	24%	14%
Total	**824,000**	**1,983,000**	**3,165,000**	**30%**	**38%**	**25%**

Source: SCAG, 2012. Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

As shown in Table 3.7-6. the average vehicle home-to-work trip duration in each county is generally similar while a greater range of average work distances is found in the different counties of the region (e.g., from a low of 13 miles in Orange County to a high of 18 miles in San Bernardino and Riverside counties). Home-to-work trip duration and distance are both greater for the inland counties of Riverside and San Bernardino, reflecting regional housing and employment distribution patterns.

TABLE 3.7-6
Summary of Existing Vehicle Work Trip Length

County	Average Home to Work Trip Distance (miles)	Average Home to Work Duration (minutes)	
	Vehicle Trips (AM Only)	Vehicle Trips (AM Only)	Transit Trips (AM Only)
Los Angeles	14	26	69
Orange	13	21	78
Riverside	18	29	95
San Bernardino	18	29	116

Source: SCAG 2012-2035 RTP/SCS Program Draft EIR.
Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

Based on average accident rates provided by Caltrans, transportation-related fatalities occur at an overall rate of 0.83 fatalities per 100 million vehicle miles traveled, taking into account the varying accident rates on different facility types (freeway, arterials) and travel modes (bus transit, rail transit) (SCAG, 2012). These specific accident rates and the resulting estimate of region-wide accidents are detailed in Table 3.7-7.

TABLE 3.7-7
Total Vehicle Fatalities

County	Fatalities (2009)	Fatalities per 100 Million Vehicle Miles Traveled	Annual Vehicle Miles Traveled per 100 Million
Los Angeles	589	0.76	778
Orange	154	0.59	261
Riverside	219	1.04	210
San Bernardino	236	1.11	212

Source: SCAG 2012-2035 RTP/SCS Program Draft EIR.
Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

A summary of home-to-work trip characteristics by county is presented in Table 3.7-8. Vehicles with single passenger occupancy are still the most common form of transportation for home to work trips, accounting for 76 percent of the trips in Los Angeles County, 81 percent of the trips in Orange County, and 82 percent of the trips in Riverside and San Bernardino County. Public transit in all forms (including school buses) carries approximately 2.4 percent of all trips in the southern California area. Of these, the greatest number of travelers is carried by buses, with lesser patronage on Metro Rail, paratransit, commuter rail and other forms of public transit services. Work trips made via public transit account for about 6.1 percent of all home-to-work trips in the area.

TABLE 3.7-8
Existing Travel Mode Split (% of County Total)

County	Person Trip Type	Drive Alone	2 Person Carpool	3 Person Carpool	Auto Passenger Trip	Transit	Non-Motorized	Total
Los Angeles	Home-Work/Univ	76%	3.4%	1.5%	7.1%	9.1%	3%	100%
	All Daily Trips	43%	8%	6.5%	24%	3.5%	14%	100%
Orange	Home-Work/Univ	81%	3.7%	1.5%	7.4%	3.4%	3%	100%
	All Daily Trips	46%	8.3%	6.8%	26%	1.4%	12%	100%
Riverside	Home-Work/Univ	82%	3.7%	1.8%	8%	1.5%	3.1%	100%
	All Daily Trips	42%	8.3%	7.3%	27%	0.72%	15%	100%
San Bernardino	Home-Work/Univ	82%	3.8%	1.8%	8.3%	1.4%	3%	100%
	All Daily Trips	43%	8.4%	7.3%	27%	0.58%	14%	100%

Source: SCAG, 2012. Data presented is for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

Regional Freeway, Highway and Arterial System

The regional freeway and highway system as shown in Figure 3.7-1 is the primary means of person and freight movement for the region. This system provides for direct automobile, bus and truck access to employment, services and goods. The network of freeways and State highways serves as the backbone of the system offering very high capacity limited-access travel and serving as the primary heavy duty truck route system.

Major freeways that transverse Los Angeles County in a generally north/south direction include the San Diego Freeway (I-405), the Golden State Freeway (I-5), the Hollywood Freeway (I-101), Pasadena Freeway (I-110), the Long Beach Freeway (I-710), and the San Gabriel Freeway I-605). Major freeways that transverse Los Angeles County in a generally east/west direction include the Santa Monica Freeway (I-10), Century Freeway (I-105), Foothill Freeway (I-210), Ronald Reagan Freeway (I-118), Pomona Freeway (I-60), and Riverside Freeway (I-91).

Major freeways that transverse Orange County in a generally north/south direction include I-405, I-5, the Orange Freeway (I-57), and the Newport Freeway (I-55), as well as toll roads located in the south-eastern portion of the County (I-241 and 261). Major freeways that transverse Orange County in a generally east/west direction include the I-91, Garden Grove Freeway (I-22), and Corona Del Mar Freeway (I-73).

Major freeways that transverse Riverside County in a generally north/south direction include the Chino Valley Freeway (I-71), Ontario Freeway (I-15), and Escondido Freeway (I-215). Major freeways that transverse Riverside County in a generally east/west direction include the I-91, I-60, and I-10.

Major freeways that transverse San Bernardino County in a generally north/south direction include the Ontario Freeway (I-15), and I-215. Major freeways that transverse San Bernardino County in a generally east/west direction include the Needles Freeway (I-40) (outside of the air Basin).

The components of the regional highway and freeway system are summarized in Table 3.7-9.

TABLE 3.7-9

Existing Regional Freeway Route Miles and Lane Miles by County

County	Freeway Route Miles	Freeway Lane Miles
Los Angeles	637	4,583
Orange	167	1,294
Riverside	309	1,722
San Bernardino	471	2,512
Total	**1,584**	**10,111**

Source: SCAG, 2012.
Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

Regional High Occupancy Vehicle System and Park & Ride System

The regional high occupancy vehicle (HOV) system consists of exclusive lanes on freeways and arterials, as well as bus ways and exclusive rights-of-way dedicated to the use of HOVs. It includes lanes on freeways, ramps and freeway-to-freeway connectors. The regional HOV system is designed to maximize the person-carrying capacity of the freeway system through the encouragement of shared-ride travel modes. HOV lanes operate at a minimum occupancy threshold of either two or three persons. Many include on-line and off-line park and ride facilities, and several HOV lanes are full "transitways" including on-line and offline stations for buses to board passengers. The current system is described in Table 3.7-10.

TABLE 3.7-10

Existing Regional Freeway HOV Total Lane Miles by County

County	HOV Total Lane Miles
Los Angeles	479
Orange	241
Riverside	83
San Bernardino	105

Source: SCAG, 2012.
Data presented is for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

Park and ride facilities are generally located at the urban fringe along heavily-traveled freeway and transit corridors and support shared-ride trips, either by transit, by carpool or vanpool. Most rail transit stations have park and ride lots nearby. There are currently 168 park and ride facilities in the southern California area, including Metrolink station parking lots. These park and ride facilities are distributed amongst the four county areas as follows: 106 in Los Angeles County, 20 in Orange County, 25 in Riverside County, and 17 in San Bernardino County.

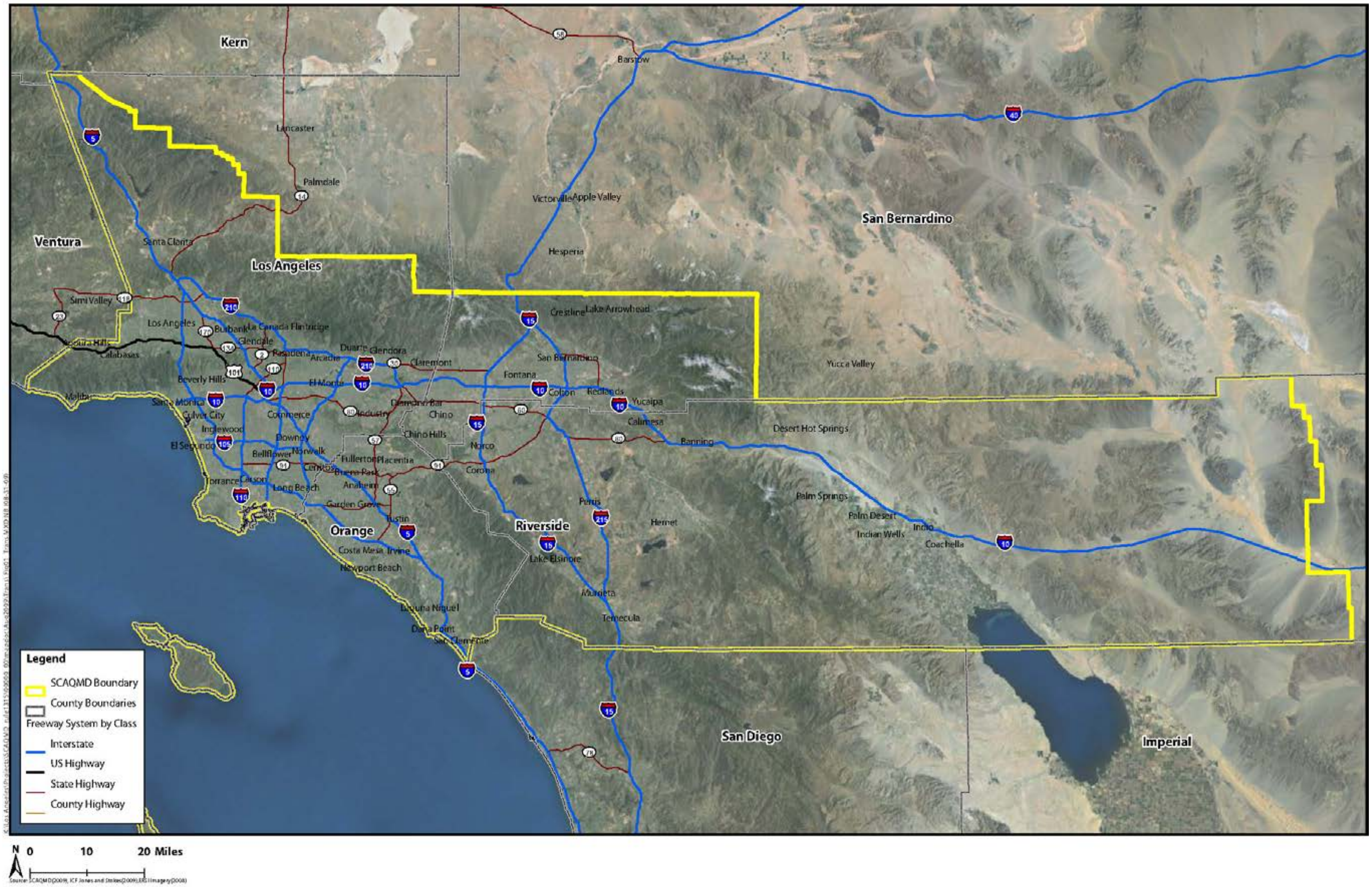

FIGURE 3.7-1
Major Freeway Routes within SCAQMD

Arterial Street System

The local street system provides access for local businesses and residents. Arterials account for over 80 percent of the total road network and carry a high percentage of total traffic. In many cases arterials serve as alternate parallel routes to congested freeway corridors. Peak period congestion on the arterial street system occurs generally in the vicinity of activity centers, at bottleneck intersections and near many freeway interchanges. The region's arterial street system is described in terms of number of miles in Table 3.7-11.

TABLE 3.7-11
Existing Regional Arterial Route Miles and Lane Miles by County

County	Arterials	Lane Miles
Los Angeles	Principal	8,843
	Minor	9,076
Orange	Principal	3,242
	Minor	3,147
Riverside	Principal	1,181
	Minor	3,235
San Bernardino	Principal	1,934
	Minor	4,365
Total	**Principal**	**15,200**
	Minor	**19,823**

Source: SCAG 2012-2035 RTP/SCS Program Draft EIR.
Data presented are for the entire county and not limited to the portion of the county located within the jurisdiction of the SCAQMD.

3.7.2.3 Goods Movement

Wholesale and retail trade, transportation, and manufacturing support over 3.3 million jobs in the region according to statistics provided by the California Employment Development Department. Goods movement includes trucking, rail freight, air cargo, marine cargo, and both domestic and international freight, the latter entering the country via the seaports, airports, and the international border with Mexico. Additionally, many cargo movements are intermodal (e.g., sea to truck, sea to rail, air to truck, or truck to rail). The goods movement system includes not only highways, railroads, sea lanes, and airways, but also intermodal terminals, truck terminals, railyards, warehousing, freight consolidation/de-consolidation terminals, freight forwarding, package express, customs inspection stations, truck stops, and truck queuing areas.

Railroads

The southern California area is served by two main line commercial freight railroads (e.g., BNSF and UP). These railroads link southern California with other regions in California and the remainder of the United States, as well as Mexico and Canada either directly or via their connections with other railroads. They also provide freight rail service within

California. In 2011, railroads moved approximately 150 million tons of cargo throughout California (SCAG, 2012). These railroads perform specific local functions and serve as feeder lines to the trunk line railroads for moving goods to and from southern California.

The two main line railroads also maintain and serve major facilities in the southern California area. Intermodal facilities in Commerce (BNSF-Hobart), East Los Angeles (UP), San Bernardino (BNSF), and Carson near the San Pedro Bay Ports (UP-ICTF), the Los Angeles Transportation Center (UP-LATC), and the UP-City of Industry yards serve on-dock rail capacity at the Port of Los Angeles (UP/BNSF) and Port of Long Beach (UP/BNSF).

BNSF and UP are both seeking approvals for new or expanded intermodal container facilities to help manage the estimated increase in container movements through the ports. BNSF is seeking approvals for the Southern California International Gateway (SCIG) facility, a new intermodal facility in the City of Los Angeles about four miles north of the Ports of Long Beach and Los Angeles and adjacent to the Alameda Corridor (LAHD, 2011). UP is seeking approvals to expand its existing Intermodal Container Transfer Facility (ICTF) near the City of Carson, adjacent to the Alameda Corridor (ICTF JPA, 2009)

All of the major rail freight corridors in the region have some degree of grade separation, but most still have a substantial number of at-grade crossings on major streets with high volumes of vehicular traffic. These crossings cause both safety and reliability problems for the railroads and for those in motor vehicles at the affected crossings. Trespassing on railroad rights-of-way by pedestrians is another safety issue affecting both freight and commuter railroads. As an example, the Colton Crossing, is an at-grade railroad crossing located south of I-10 between Rancho Avenue and Mount Vernon Avenue in the City of Colton, where BNSF's San Bernardino Line crosses UP's Alhambra/Yuma Lines. In 2008, the Colton Crossing saw on average 110 freight trains per day.

The southern California area is also served by two short line or switching railroads:

- The Pacific Harbor Line (formerly the Harbor Belt Railroad) handles all rail coordination involving the Port of Los Angeles and Port of Long Beach, including dispatching and local switching in the harbor area.
- Los Angeles Junction Railway Company, owned by BNSF, provides switching service in the Vernon area for both the BNSF and UP.

Another key component of the regional rail network is the Alameda Corridor, a 20-mile, four-lane freight rail expressway that began operations in April 2002. In 2010, approximately 14,177 intermodal trains transited the Alameda Corridor, an approximate increase of 8.6 percent since 2009 (SCAG, 2012).

Marine Ports

Southern California is served by three major deep-water seaports (e.g., Port of Los Angeles, Port of Long Beach, and Port of Hueneme). However, the Port of Hueneme is not within the jurisdiction of the SCAQMD. The Port of Los Angeles and Port of Long Beach handle trade from Asia and North America, and are served by the two major railroads (e.g., BNSF and UP), as well as numerous trucking companies in southern California. The Port of Hueneme handles primarily automobile and agricultural products. Both the Port of Los Angeles and the Port of Long Beach are full service ports with facilities for containers, autos and various bulk cargoes. With an extensive landside transportation network, these three ports moved more than 310 million metric tons of cargo in 2010 (SCAG, 2012).

The Port of Los Angeles and Port of Long Beach dominate the container trade in the Americas by shipping and receiving more than 11.8 million twenty-foot Equivalent Units (TEUs) of containers in 2009. Together, these two ports rank third in the world, behind Rotterdam and Hong Kong, as the busiest maritime ports (SCAG, 2012).

3.7.2.4 Public Transit, Bicycle or Pedestrian Facilities

Public Transit

In southern California public transit service is comprised of local and express buses, transit ways, Rapid Bus, and urban rail, including subway and light rail, principally centered in the core of Los Angeles County. Transit service is provided by approximately 67 separate public agencies. Twelve of these agencies provide 91 percent of the existing public bus transit service. Local service is supplemented by municipal lines and shuttle services. Private bus companies provide additional regional service.

Transit ridership was approximately 708 million in 2010 in southern California (SCAG, 2012). The largest provider of public transit service in Los Angeles County is the Metro, which provides bus service and an urban light rail system and subway. In 2010, the Metro system experienced approximately 41.9 million average monthly boardings (SCAG, 2010).

The largest provider of public transit service in Orange County is OCTA, which operates 77 bus local and express routes and approximately 62,000 bus stops located throughout the urbanized portions of Orange County. In 2010, the OCTA system experienced approximately 4.8 million average monthly boardings (SCAG, 2010).

The largest provider of public transit service in Riverside County is the Riverside Transit Agency, which operates 231 buses on approximately 43 local and express routes. In 2010, the system experienced approximately 950,000 average monthly boardings (SCAG, 2010).

The largest provider of public transit service in San Bernardino County is Omnitrans, which operates 277 buses over approximately 27 routes. In 2010, the system experienced approximately 1.3 million average monthly boardings (SCAG, 2010).

Metro Rail System

Within the district, the Los Angeles County Metropolitan Transit Authority (Metro) provides urban rail transit service on six lines within Los Angeles County. The Blue Line extends from Long Beach to the 7th Street Metro Center in downtown Los Angeles. The Red Line connects Union Station with North Hollywood via the Metro Center, the Gold Line connects Union Station with Pasadena, and the Green Line extends from Redondo

Beach to Norwalk. The Purple Line connects Koreatown in the mid-Wilshire District to Union Station. The Metro Expo Line connects the 7th Street Metro Center in downtown Los Angeles to Culver City. Other Metro operated urban transit systems include the Orange Line which connects with the northern terminus of the Red Line in North Hollywood and serves much of the northwestern portion of Los Angeles County, and the Eastside Gold Line Extension, which provides rail transit service to East Los Angeles. The Metro Rail system has a total of 87 route miles that serve a total of 80 stations. Ridership on the system is about 303,000 boardings per day (SCAG, 2012)

Regional Commuter Rail

Metrolink is a commuter rail service that is governed and operated by the Southern California Regional Rail Authority (SCRRA), a joint powers authority that consists of the following county agencies tasked with reducing highway congestion and improving mobility throughout southern California: 1) Los Angeles County Metropolitan Transportation Authority (Metro); 2) Orange County Transportation Authority (OCTA); 3) Riverside County Transportation Commission; 4) San Bernardino Associated Governments (SanBAG); and, 5) Ventura County Transportation Commission. Metrolink serves as the link between six Southern California counties by providing commuters seamless transportation connectivity options. Metrolink currently operates seven routes including five from downtown Los Angeles to Ventura, Lancaster, San Bernardino, Riverside and Oceanside; one from San Bernardino to Oceanside; and one from Riverside via Fullerton or City of Industry to downtown Los Angeles. The system operates about 144 trains on weekdays, 40 trains on Saturdays, and 26 trains on Sundays to 55 stations on 512 miles of track. Average weekday ridership is approximately 40,544 passengers (SCAG, 2012).

Amtrak provides regional and inter-regional service from San Diego to San Luis Obispo along the Pacific Surfliner corridor. Amtrak also operates four interstate routes within the region that on average have one daily trip.

Bicycle and Pedestrian Facilities

Biking and walking tend to play a bigger role in densely-populated, mixed land use areas of the region. However, in 2009, less than four percent of commuters within the SCAG region, of which the district is a subset, traveled to work via biking or walking (0.7 percent bicycled and 2.5 percent walked)[1]. Current transit infrastructures provide 97 percent of residents in the SCAG region with access to transit via bicycle and 86 percent access to transit by walking.

The region's bikeways include Class I bikeways, which are shared-use paths that are also used by pedestrians. Class II bikeways are striped lanes in streets, and Class III bikeways are signed routes. Nearly 4,615 miles of Class I and II bikeways exist throughout the region, as well as mountain bike trails. The City of Los Angeles alone has more than 216 miles of

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1 SCAG. 2012. 2012 – 2035 Regional Transportation Plan/Sustainable Communities Strategy, adopted April 2012, p. 53. http://rtpscs.scag.ca.gov/Documents/2012/final/f2012RTPSCS.pdf

Class I and II bikeways. In addition, local jurisdictions in the region have proposed an additional 4,980 miles of bikeways (SCAG, 2012).

Pedestrian access at and near public transit, in most major commercial areas, and many residential areas is facilitated by sidewalks, a number of pedestrian malls, and in some cases local jogging and pedestrian trails or paths.

CHAPTER 4

ENVIRONMENTAL IMPACTS

Potential Environmental Impacts and Mitigation Measures
- **Aesthetics**
- **Air Quality and Greenhouse Gases**
- **Energy**
- **Hazards and Hazardous Materials**
- **Hydrology and Water Quality**
- **Solid and Hazardous Waste**
- **Transportation and Traffic**

Potential Environmental Impacts Found Not to be Significant

Significant Irreversible Environmental Changes

Potential Growth-Inducing Impacts

Consistency

4.0 POTENTIAL ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES

The CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project [CEQA Guidelines §15126.2(a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The discussion of environmental impacts may include, but is not limited to: the resources involved; physical changes; alterations of ecological systems; health and safety problems caused by physical changes; and other aspects of the resource base, including water, scenic quality, and public services. If significant adverse environmental impacts are identified, the CEQA Guidelines require a discussion of measures that could either avoid or substantially reduce any adverse environmental impacts to the greatest extent feasible [CEQA Guidelines §15126.4].

CEQA Guidelines indicate that the degree of specificity required in a CEQA document depends on the type of project being proposed [CEQA Guidelines §15146]. The detail of the environmental analysis for certain types of projects cannot be as great as for others. For example, the environmental document for projects, such as the adoption or amendment of a comprehensive zoning ordinance or a local general plan, should focus on the secondary effects that can be expected to follow from the adoption or amendment, but the analysis need not be as detailed as the analysis of the specific construction projects that might follow. As a result, this PEA analyzes impacts on a regional level and impacts on the level of individual industries or individual facilities only where feasible.

The categories of environmental impacts to be studied in a CEQA document are established by CEQA [Public Resources Code, §21000 et seq.], and the CEQA Guidelines, as promulgated by the State of California Secretary of Resources. Under the CEQA Guidelines, there are 17 environmental topic areas in which potential adverse impacts from a project are evaluated. Projects are evaluated against the environmental categories in an Environmental Checklist and those environmental categories that may be adversely affected by the proposed project are further analyzed in the appropriate CEQA document.

The proposed project is based on reducing NOx RTC holdings from certain NOx RECLAIM RTC holders. The likely possibility is that the affected source categories will reduce actual NOx emissions via physical modifications to a wide variety of equipment by installing new air pollution control equipment or modifying existing air pollution control equipment. Because of the number of potentially affected equipment units, these physical changes, while reducing NOx emissions, may cause potentially significant adverse secondary impacts. Pursuant to CEQA, an Initial Study, including an environmental checklist, was prepared for this project (see Appendix F). Of the 17 potential environmental impact categories, the following seven topic areas were identified in the NOP/IS as being potentially adversely affected by the proposed project: aesthetics; air quality and GHG emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic. Eight comment letters were received relative to the NOP/IS. These comment letters and responses to the comments can be found in Appendix G of this document.

The seven environmental impact areas that were identified as potentially significant in the NOP/IS are further evaluated in detail in this PEA. The environmental impact analysis for each environmental topic incorporates a "worst-case" approach. This approach entails the premise that whenever the analysis requires that assumptions be made, assumptions that result in the greatest adverse impacts are typically chosen. This method ensures that all potential effects of the proposed project are documented for the decision-makers and the public. Accordingly, the following analyses use a conservative "worst-case" approach for analyzing the potentially significant adverse environmental impacts associated with the implementation of the proposed project.

The proposed project consists of applying a "shave" to holders of the top 90 percent of NOx RTCs (e.g., refineries, power plants, and other large RTC holders). The amount of the shave is weighted by a BARCT reduction contribution to achieve an overall reduction of 14 tons of NOx per day from current total RTC holdings (starting with the facility holding the most RTCs and proceeding to include 90 percent of the RTCs) by 2022 according to the following implementation schedule as summarized in Table 4.0-1:

Table 4.0-1
Implementation Schedule for NOx RTC Reductions

Implementation Year	Amount of NOx RTC Reductions (tons/day)
2016	4
2018	2
2019	2
2020	2
2021	2
2022	2
TOTAL	**14**

The NOx RTC shave will apply to 56 ~~65~~ facilities. In addition, the RTC shave will apply to RTC investors, but they will be treated as 1 company. The RTC shave will apply to refineries, certain non-major facilities, and all power plants. The shave is distributed as follows:

- 66~~67~~% shave for 9 refineries and investors (treated as one facility)
- 49~~47~~% shave for 21 electricity generating facilities (EGFs) ~~30~~ power plants
- 49~~47~~% shave for 26 non-major facilities
- 0% shave for 219 ~~210~~ remaining facilities

Note that for the remaining 219 ~~210~~ facilities, no NOx RTC shave is proposed because no new BARCT was identified for the types of equipment and source categories at these facilities.

SCAQMD staff is proposing BARCT levels that will be applicable to the refinery sector (e.g., FCCUs, refinery process heaters and boilers, refinery gas turbines, petroleum coke calciner, and SRU/TGUs) and the non-refinery sector (e.g., container glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces, non-refinery/non-power plant gas turbines, ICEs, and cement kilns). On an equipment/process basis, Table 4.0-2 summarizes the potential control technologies that will be considered as part of the BARCT analysis for the proposed project.

Table 4.0-2

BARCT Control Technology Options for Top NOx Emitting Equipment/Processes

Equipment/Process	BARCT Control Technology To Be Analyzed in PEA
FCCUs	1. SCR 2. LoTOx™ with WGS
Refinery Process Heaters and Boilers	SCR
Refinery Gas Turbines	SCR
SRU/TGUs	1. LoTOx™ with WGS 2. SCR
Petroleum Coke Calciner	1. UltraCat DGS 2. LoTOx™ with WGS
Portland Cement Kilns	None[1]
Container Glass Melting Furnaces	1. SCR 2. UltraCat DGS
Sodium Silicate Furnaces	1. SCR 2. UltraCat DGS (without sorbent)
Metal Heat Treating Furnaces	SCR
ICEs (Non-Refinery/Non-Power Plant)	SCR

Key: SCR = Selective Catalytic Reduction; WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber

Of the 56 ~~65~~ facilities that would be subject to a shave of the NOx RTC holdings , the BARCT analysis found that it would be both feasible and cost-effective for operators of 20 facilities to install new control equipment or modify existing control equipment in response to the proposed NOx RTC shave for facilities which operate with current SCAQMD permits. Of the 20 facilities, 11 facilities belong to the non-refinery sector and 9 facilities belong to the refinery sector. Thus, the proposed project may result in the installation and operation of new or ~~the~~ modified~~cation of~~ existing NOx emission control equipment for 20 of these industrial equipment and processes (e.g., 9 facilities from the refinery sector and 11 facilities from the non-refinery sector). Accordingly, the analyses in the following subchapters for each environmental topic area focus on the potential environmental impacts that may occur as a result of installing and operating new or modified~~ying~~ existing NOx emission control equipment at these 20 facilities.

[1] Because of CPCC's current permitting status for their Portland cement kilns (e.g., the permits were surrendered), CPCC operators will not be able to retrofit the Portland cement kilns with air pollution control equipment in response to the proposed project without first dealing with the permitting issues for the cement kilns. Thus, the installation of control technology and the secondary adverse environmental impacts that may be associated with such control technology is not a reasonably foreseeable consequence for CPCC under the present circumstances. Further, there are no other facilities in SCAQMD's jurisdiction that operate Portland cement kilns. Thus, this PEA does not contain an environmental analysis of the control technologies that were originally contemplated in the NOP/IS for the CPCC facility.

At the time the Draft PEA was released for the public review and comment period (from August 14, 2015 to October 6, 2015), the analysis was based on the version of the rules that was presented at the July 22, 2015 Public Workshop. Subsequent to release of the Draft PEA, modifications were made to the proposed project and some of the revisions were made in response to verbal and written comments received. Most of the subsequent revisions that are identified in strikeout/underlined text in Chapter 2 of this PEA are administrative in nature and thus, would not create any environmental impacts. However, there are two key revisions proposed which SCAQMD staff has received comments suggesting that their environmental effects, if any, be addressed in the PEA, as follows: 1) revisions have been made to the proposed project that would include amending Rule 2001 – Applicability, to allow electricity generating facilities (EGFs) to exit or opt out of the RECLAIM program provided that certain criteria are met (see the project description in Chapter 2 which describes the proposed amendments to Rule 2001); and 2) revisions have been made to Rule 2002 that would require facilities to surrender RTCs if the facility undergoes a complete shutdown or if equipment that represents more than 25 percent of facility emissions is shutdown.

Option for EGF Opt Out: Under the proposed amendments to Rule 2001, an EGF, excluding cogeneration plants, would be allowed to exit the RECLAIM program, provided that at least 99 percent of the facility's NOx emissions for the most recent three full compliance years are from equipment that meets current BACT or BARCT for NOx. This stringent criteria was deliberately crafted to ensure that the emissions from EGFs operating under a RECLAIM permit would not change if these EGF facilities opt out of RECLAIM and instead, operate under a command-and-control permit. In addition, if an EGF decides to opt out from RECLAIM, it would need to surrender a pre-defined amount of NOx RTCs to be retired from the NOx RTC market. For EGFs with existing permits issued prior to the inception date of the RECLAIM program, the amount to be surrendered would be equivalent to the amount of NOx RTCs initially allocated to the facility upon entry into RECLAIM as adjusted by the 2005 and proposed shaves; for other EGFs with all permits issued on or after the RECLAIM inception date, the amount would be equivalent to the quantity required to be held by the facility pursuant to Rule 2005 – New Source Review. The requirement to surrender RTCs will prevent other facilities within the RECLAIM program from using RTCs from EGFs and emitting more NOx. In addition, once an EGF is under command-and-control, the EGF will no longer have the ability to purchase RTCs in the event their emissions increase above their RTC holdings. Instead, they would be subject to a facility-wide emission limit based on their surrendered RTCs. In addition, any future increases in emissions would be subject to the emissions offset and all other requirements pursuant to Regulation XIII – New Source Review.

Actual emissions for EGFs fluctuate relative to the potential to emit (PTE), and this would remain true whether the EGF operates under a RECLAIM permit or under a command-and-control permit. However, without having the flexibility of purchasing RTCs that was afforded to EGFs under a RECLAIM permit, an EGF operating under a command-and-control permit would be limited to having emissions operate at or below the permitted level. For these reasons, SCAQMD staff believes there would be no substantial change in actual or PTE emissions from the existing setting (e.g., an EGF operating under a RECLAIM permit) when compared to the proposed project which would allow an EGF to exit RECLAIM and operate pursuant to a command-and-control permit.

Surrender RTCs for Complete Facility Closures or Equipment Shutdowns: Since the adoption of RECLAIM, facilities which planned to shut down were not restricted from selling off their RTCs prior to facility closures. RTCs resulting from shutdowns are not subject to the best available control technology (BACT) discount that applies to non-RECLAIM sources and are not based on the emissions from the last two years of operation.

As a consequence, staff estimated that large amounts of RTCs that are in the market can be traced to the sale of RTCs from facilities that have, or are planning to, shut down. As shown in Table 2 of the Socioeconomic Report, facility shutdowns amounted to 2.62 tpd of actual NOx emission reductions between 2006 and 2012, which was just less than two-thirds of the 4 tpd actual total NOx emission reductions over the same period. However, NOx RTCs that were previously held by these shutdown facilities were never removed from the market, thus exerting a downward pressure on the RTC market prices. This, in turn, had the effect of dis-incentivizing some of the the remaining NOx RECLAIM facilities from installing cost-effective control equipment or making other changes at their facilities.

Under Proposed Amended Rule 2002, any facility that permanently shuts down some or all equipment with emissions greater than or equal to 25 percent of the facility emissions for any quarter within the previous two compliance years would need to surrender NOx RTCs to be retired from the market. By reducing the amount of available RTCs on the market, facilities that remain in the RECLAIM program would be induced to reduce NOx emissions by installing new or modifying existing air pollution control equipment instead of purchasing RTCs. The analysis of installing new or modifying existing air pollution control equipment is already addressed in this PEA.

Thus, after careful review of the proposed revisions, SCAQMD staff believes the inclusion of an EGF opt out option and requiring facilities undergoing a shutdown to surrender RTCS would not constitute: 1) significant new information; 2) a substantial increase in the severity of an environmental impact; 3) provide new information of substantial importance relative to the draft document; or, 4) create new, avoidable significant effects. As a result, these revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5.

SUBCHAPTER 4.1

AESTHETICS

Introduction

Significance Criteria

Potential Aesthetics Impacts and Mitigation Measures

Cumulative Aesthetic Impacts

Cumulative Mitigation Measures

4.1 AESTHETICS

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in aesthetics impacts. The aesthetic impact analysis in this ~~Draft~~ Final PEA identifies the net effect on aesthetic resources from implementing the proposed project.

4.1.1 Introduction

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of new or the modification of existing NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx emissions at the affected facilities, once operational, which will provide air quality and human health benefits to the public. However, the NOP/IS identified potentially adverse aesthetics impacts from installing new or modifying existing air pollution control equipment and committed to analyzing in the PEA whether these activities would substantially degrade the existing visual character or quality of the site and its surroundings. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse aesthetics impacts. The analysis of these impacts can be found in Section 4.1.3.

4.1.2 Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

4.1.3 Potential Aesthetics Impacts and Mitigation Measures

Table 4.1-1 summarizes the estimated number of NOx emission control devices per sector and per equipment/source category. The different types of control devices include Selective Catalytic Reduction (SCR), a proprietary Low Temperature Oxidation technology (LoTOx™)

with or without a Wet Gas Scrubber (WGS), and catalyst impregnated filters with a Dry Gas Scrubber (UltraCat DGS). In total, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx™ with WGSs, one LoTOx™ without WGS, and three UltraCat DGSs.

Table 4.1-1
Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	2 SCRs 2 LoTOx™ with WGSs* 1 LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	5	5 LoTOx™ with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx™ with WGS or 1 UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	1	2 SCRs or 1 UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	7	13 SCRs and 1 SCR replacement
		TOTAL	**114 to 117 SCRs** **7 to 8 LoTOx™ with WGSs** **1 LoTOx™ without WGS** **0 to 3 UltraCat DGSs**

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

4.1.3.1 Potential Aesthetics Impacts During Construction

Implementation of the proposed project could potentially result in construction activities at 20 NOx RECLAIM facilities, which are complex industrial facilities. The physical changes that are expected focus on the installation of new or the modification of existing control equipment for the following stationary sources of NOx: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces.

Due to the large size profiles of the affected equipment involved, the construction activities that may be associated with installing new or modifying existing NOx control equipment are expected to require the use of heavy-duty construction equipment, such as cranes, tractor/loader/backhoes, forklifts, et cetera. The use of cranes, in particular, because of their height when fully extended, may be visible to the surrounding areas and temporarily change the skyline of the affected facilities, depending on where they are located within each facility's property. Except for the use of cranes, the majority of the construction equipment is expected to be low in height and not substantially visible to the surrounding area due to existing fencing along the property lines and existing structures currently within the facilities that would buffer the views of the construction activities.

Because each affected facility is located in heavy industrial areas, the construction equipment is not expected to be substantially discernable from what exists on-site for routine operations and maintenance activities. Further, the construction activities are not expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities are expected to occur within the confines of each existing facility and are expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility.

Lastly, the construction activities are expected to be temporary in nature and will cease following completion of the equipment installation or modifications. All construction equipment will be removed following completion of the proposed project. For these reasons, the construction activities are not expected to substantially degrade the existing visual character or quality of each affected site and the surroundings of each affected site. Thus, adverse visual continuity aesthetics impacts during construction are expected to be less than significant.

4.1.3.2 Aesthetics Mitigation During Construction

Less than significant adverse impacts associated with aesthetics are expected from the proposed project during construction, so no mitigation measures are required.

4.1.3.3 Remaining Aesthetics Impacts During Construction After Mitigation

The aesthetics analysis concluded that potential aesthetics impacts during construction would be less than significant, no mitigation measures were required. Thus, aesthetics impacts during construction remain less than significant.

4.1.3.4 Potential Aesthetics Impacts During Operation

Of the technologies proposed as BARCT for NOx control, only WGS technology was identified as having the potential to generate adverse aesthetic operational impacts. WGS technology is potentially BARCT for two FCCUs, five SRU/TGUs and one coke calciner.

SCRs, Ultracat DGSs, and LoTOx^{TM} technology without a WGS, if installed (or modified) and operated, would be expected to blend in with the existing industrial profile at the affected facilities because the heights of these units are typically smaller when compared to neighboring existing equipment onsite at a refinery and their associated stack heights would be about the same or shorter than existing stacks within the affected facilities. However, operation of one WGS is expected to generate a substantial, continuous steam plume that is white in appearance. A steam plume is generated as the result of using water to reduce particulate emissions in the WGS, and consists of water vapor and clean, but warm flue gas in the exit stream of the scrubber. As a result of atmospheric changes in temperature and humidity, the vapor plume is expected to be smaller on warm, dry days and larger on cool, damp days. Under certain atmospheric conditions, the steam plume from a WGS could extend as much as 1,500 feet in length from a relatively high flue gas stack at approximately 200 feet above grade. As the vapor travels away from the stack, the plume will eventually evaporate and become clear.

As a point of comparison, other equipment operating at these industrial facilities routinely generate steam plumes on a similar scale as part of their day-to-day operations (e.g., cooling towers, cogeneration plants, etc.). In addition, the refineries, which operate the FCCUs, SRU/TGUs, and coke calciner, are located near the Ports of Los Angeles and Long Beach whose facilities, such as the Harbor Cogeneration Plant and the Long Beach SERRF, routinely generate multiple steam plumes.

The Philips 66 Refinery in Wilmington recently installed a WGS to reduce NOx and PM10 emissions from their FCCU. The potential adverse aesthetics impacts were analyzed for this project in the Final Environmental Impact Report for the ConocoPhillips Los Angeles Refinery PM10 and NOx Reduction Projects[1]. The aesthetics analysis acknowledged that while the steam plume from the WGS would be visible, it was not expected to adversely affect the visual continuity of the surrounding area and none of the significance criteria were expected to be exceeded.

Further, in 2010, a similar aesthetics analysis relative to multiple WGSs and their associated steam plumes was also conducted in the Final Program Environmental Assessment prepared for the amendments to the SOx RECLAIM program[2]. This analysis in the SOx RECLAIM Final PEA also came to the same less than significant aesthetics impact conclusion as the Final EIR for the ConocoPhillips Los Angeles Refinery PM10 and NOx Reduction Projects, except that the SOx RECLAIM Final PEA assumed that up to as many as 11 WGSs could be installed.

For these reasons, if any WGS is installed as part of the proposed project at any of the affected facilities and even if all eight WGSs are installed, each steam plume, though visible, would not be expected to significantly adversely affect the visual continuity of the surrounding area of each affected facility because no scenic highways or corridors exist within the areas of the refineries. Further, the visual continuity of the surrounding area is

[1] SCAQMD, Final Environmental Impact Report for the ConocoPhillips Los Angeles Refinery PM10 and NOx Reduction Projects, SCH No. 2006111138, certified June 12, 2007. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects/permit-project-documents---year-2007/feir-for-conocophillips-pm10-and-nox-reduction

[2] SCAQMD, Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), SCH No. 2009061088, SCAQMD No. 06182009BAR, certified November 5, 2010. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2010/final-program-environmental-assessment-for-proposed-amended-regulation-xx.pdf?sfvrsn=4

not expected to be adversely impacted because each WGS, if constructed, will be built within the confines of industrial areas and would be visually consistent with the profiles of the existing affected facilities. Thus, even if each WGS could be visible, depending on the location within each property boundary, the aesthetic significance criteria would not be exceeded.

Overall, the aesthetics impacts are expected to be less than significant during operation for the proposed project.

4.1.3.5 Aesthetics Mitigation During Operation

Less than significant adverse impacts associated with aesthetics are expected from the proposed project during operation, so no mitigation measures are required.

4.1.3.6 Remaining Aesthetics Impacts During Operation After Mitigation

The aesthetics analysis concluded that potential aesthetics impacts during operation would be less than significant, no mitigation measures were required. Thus, aesthetics impacts during operation remain less than significant.

4.1.4 Cumulative Aesthetic Impacts

Because the project-specific aesthetic impacts do not exceed any applicable significance thresholds either during construction or operation, they are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, do not generate significant adverse cumulative aesthetics impacts.

4.1.5 Cumulative Mitigation Measures

Because the project-specific aesthetic impacts during construction and operation are not considered to be cumulatively considerable, no cumulative mitigation measures are required.

SUBCHAPTER 4.2

AIR QUALITY AND GREENHOUSE GASES

Introduction

Significance Criteria

Potential Air Quality Impacts and Mitigation Measures

Cumulative Air Quality Impacts

Cumulative Mitigation Measures

Greenhouse Gas Impacts

Greenhouse Gas Mitigation Measures

4.2 AIR QUALITY AND GREENHOUSE GASES

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in air quality and greenhouse gas (GHG) impacts. The air quality and GHG analysis in this PEA identifies the net effect of air quality and GHG impacts from implementing the proposed project.

4.2.1 Introduction

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx at the affected facilities, which will provide air quality and human health benefits to the public. However, installing new or modifying existing air pollution control equipment is expected to have potentially adverse air quality and GHG impacts.

The environmental analysis assumes that installation of NOx control technologies for the affected sources will reduce NOx emissions overall, but construction activities associated with both the installation of new control devices and the modification of existing control devices will create secondary air quality impacts (e.g., emissions), which can adversely affect local and regional air quality. A project may generate emissions both during the period of its construction and through ongoing daily operations. During installation or modification of add-on air pollution control devices, emissions may be generated by onsite construction equipment and by offsite vehicles used for worker commuting. After construction activities are completed, emissions may be generated by the operation of the add-on air pollution control devices (as GHGs) and offsite vehicles used for delivering fresh materials needed for operations (e.g., chemicals, fresh catalyst, etc.) and hauling away solid waste for disposal or recycling (e.g., spent catalyst). The analysis of these impacts can be found in Section 4.2.3. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse air quality and GHG impacts. Refer to Appendix E for the calculations used to estimate secondary construction- and operational-related air quality impacts.

4.2.2 Significance Criteria

To determine whether air quality and GHG impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the following criteria. If impacts exceed any of the significance thresholds in Table 4.2-2, they will be considered significant. All feasible mitigation measures will be identified in Section 4.2.3 and implemented to reduce significant impacts to the maximum extent feasible. The SCAQMD makes significance determinations for construction impacts based on the maximum or peak daily emissions during the construction period, which provides a "worst-case" analysis of the construction emissions. Similarly, significance determinations for operational emissions are based on the maximum or peak daily allowable emissions during the operational phase.

The proposed project will have significant adverse air quality impacts if any one of the thresholds in Table 4.2-2 are equaled or exceeded.

4.2.3 Potential Air Quality Impacts and Mitigation Measures

Table 4.2-1 summarizes the estimated number of NOx emission control devices per sector and per equipment/source category. The different types of control devices include Selective Catalytic Reduction (SCR), a proprietary Low Temperature Oxidation technology (LoTOx™) with or without a Wet Gas Scrubber (WGS), and catalyst impregnated filters with a Dry Gas Scrubber (UltraCat DGS). In total, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx™ with WGSs, one LoTOx™ without WGS, and three UltraCat DGSs.

Table 4.2-1
Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	2 SCRs 2 LoTOx™ with WGSs* 1 LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	5	5 LoTOx™ with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx™ with WGS or 1 UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	1	2 SCRs or 1 UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	7	13 SCRs and 1 SCR replacement
		TOTAL	**114 to 117 SCRs** **7 to 8 LoTOx™ with WGSs** **1 LoTOx™ without WGS** **3 UltraCat DGSs**

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

Table 4.2-2
SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs), Odor, and GHG Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
GHG	10,000 MT/yr CO2eq for industrial facilities	
Ambient Air Quality Standards for Criteria Pollutants [d]		
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)	
PM10 24-hour average annual average	$10.4\ \mu g/m^3$ (construction)[e] & $2.5\ \mu g/m^3$ (operation) $1.0\ \mu g/m^3$	
PM2.5 24-hour average	$10.4\ \mu g/m^3$ (construction)[e] & $2.5\ \mu g/m^3$ (operation)	
SO2 1-hour average 24-hour average	0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)	
Sulfate 24-hour average	$25\ \mu g/m^3$ (state)	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)	
Lead 30-day Average Rolling 3-month average	$1.5\ \mu g/m^3$ (state) $0.15\ \mu g/m^3$ (federal)	

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day ppm = parts per million $\mu g/m^3$ = microgram per cubic meter ≥ = greater than or equal to
MT/yr CO2eq = metric tons per year of CO2 equivalents > = greater than

4.2.3.1 Construction Analysis

Construction-related emissions can be distinguished as either onsite or offsite. Onsite emissions generated during construction principally consist of exhaust emissions (NOx, SOx, CO, VOC, PM2.5 and PM10) from heavy-duty construction equipment operation, fugitive dust (primarily as PM10) from disturbed soil, and VOC emissions from asphaltic paving and painting. Offsite emissions during the construction phase normally consist of exhaust emissions and entrained paved road dust (primarily as PM10) from worker commute trips, material delivery trips, and haul truck material trips to and from the construction site. In general, limited construction emissions from site preparation activities, which may include earthmoving/grading, are anticipated because the sites, typically, have already been graded and paved. Further, operators at each affected facility who construct NOx control equipment that utilize chemicals as part of the NOx control equipment operations, such as a new ammonia or caustic storage tank, may also need to build a containment berm large enough to hold 110 percent of the tank capacity in the event of an accidental release, pursuant to U.S. EPA's spill prevention control and countermeasure regulations.

The space limitations within each affected facility have been evaluated and each facility was determined to have sufficient space to install new NOx control equipment or modify existing NOx control equipment. However, because installation of larger NOx air pollution control equipment such as a new scrubber (WGS or DGS), may need to occupy the space of previous equipment, demolition activities were assumed to occur prior to the equipment installation to remove any existing equipment or structures (as applicable), remove the old piping and electrical connections, and break up the old foundation with a demolition hammer. For these reasons, digging, earthmoving, grading, slab pouring, or paving activities are anticipated and were analyzed.

The type of construction-related activities attributable to installing new NOx control equipment or modifying existing NOx control equipment would consist predominantly of deliveries of steel, piping, wiring, chemicals, catalysts, and other materials, and would also involve maneuvering the materials within the site via a variety of off-road and on-road equipment such as a crane, forklift et cetera or haul truck, respectively. If a new foundation is not needed, to establish footings or structure supports, some concrete cutting and digging may be necessary in order to re-pour new footings prior to building above the existing foundation.

Non-Refinery Facilities

Of the 275 facilities subject to the NOx RECLAIM Rules, there are currently 206 facilities that belong to the non-refinery sector. SCAQMD staff conducted an analysis of the potential feasibility and cost-effectiveness of adding controls to reduce NOx from all of these facilities. This analysis found that it would be both feasible and cost-effective for only 11 non-refinery facilities to install air pollution controls. However, for all other non-refinery facilities, because of the lack of feasible of cost-effective controls, operators of the remaining non-refinery facilities will comply with their NOx shave through the purchase of RTCs which will have no environmental impact.

In 2011, the 11 non-refinery facilities emitted approximately 2.82 tons per day or 14 percent of the total NOx emitted from facilities in the RECLAIM program. These facilities include the following equipment/source categories: container glass melting furnaces, glass melting furnace facilities, sodium silicate furnaces, metal heat treating furnaces, stationary ICEs and non-power plant stationary gas turbines. As stated previously, under the proposed project, operators of these facilities could potentially install SCR technology or UltraCat filtration units to reduce NOx emissions. For the purpose of conducting a worst-case analysis, 34 SCR units and one UltraCat filtration unit are assumed to be installed at the 11 non-refinery affected facilities. It is possible that another UltraCat filtration unit may also be installed instead of one of the 34 SCR units.

Ammonia or urea is necessary to operate SCR and UltraCat filtration technology, and tanks to store these chemicals would also need to be installed. The size of each ammonia tank needed to operate the SCR units and one UltraCat filtration unit have been estimated to range between 600 and 10,000 gallons in capacity. If a second UltraCat filtration unit is installed in lieu of one of the 34 SCR units, two 300 gallon ammonia portable totes instead of one ammonia storage tank would be needed[3]. Also, since an adsorbent would be needed to operate the second UltraCat unit, a 5,000-cubic foot hydrated lime silo would be needed. Because the non-refinery affected facilities are existing facilities, it was assumed that no more than one acre of area would need to be disturbed at a single facility at a given time. Construction was assumed to consist of four phases: 1) demolition; 2) site preparation; 3) paving; and, 4) building of the emission control units along with supporting devices and structures. A list of the construction equipment expected to be needed for each construction phase at a single non-refinery affected facility is presented in Table 4.2-3 below.

It is important to note that six of the non-refinery affected facilities have space restrictions that could limit mobility throughout the facility, and these same six facilities could potentially install more than one SCR unit. As such, the analysis assumes that the same amount of construction equipment would be used at these facilities, but that the construction duration would be extended over a longer period of time.

Construction emissions associated with installing air pollution control equipment at each of the 11 non-refinery facilities were estimated using the California Emission Estimator Model (CalEEMod). To allow for enough lead time needed to procure contracts and order equipment, construction is expected to begin in 2016 and, depending on the facility, construction could last over a year. Table 4.2-4 presents the peak daily emissions from construction activities to install control equipment at one facility. To conduct a conservative analysis, overlapping construction activities were assumed to occur at all 11 of the non-refinery facilities. Table 4.2-5 presents the peak daily emissions if construction occurs simultaneously at all 11 non-refinery facilities.

[3] For a worst-case analysis, the impacts from a second UltraCat unit have been included in the calculations.

Table 4.2-3
Construction Equipment That May Be Needed To Install
One Air Pollution Control Device at One Non-Refinery Facility

Construction Phase	Off-Road Equipment Type	Amount	Daily Usage Hours
Building Construction	Cranes	1	6
Building Construction	Forklifts	1	6
Building Construction	Generator Sets	1	8
Building Construction	Tractors/Loaders/Backhoes	1	6
Building Construction	Welders	2	8
Building Construction	Aerial Lifts	1	8
Demolition	Concrete/Industrial Saws	1	8
Demolition	Rubber Tired Dozers	1	8
Demolition	Tractors/Loaders/Backhoes	1	8
Demolition	Cranes	1	8
Paving	Cement and Mortar Mixers	1	6
Paving	Paving Equipment	1	8
Paving	Plate Compactors	1	6
Paving	Tractors/Loaders/Backhoes	1	8
Site Preparation	Rubber Tired Dozers	1	7
Site Preparation	Tractors/Loaders/Backhoes	1	8
Site Preparation	Trenchers	1	8

Table 4.2-4
Peak Daily Construction Emissions per Control Equipment
at One Non-Refinery Facility

Peak Daily Construction Emissions	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Unmitigated	3.7	31.7	21.7	0.03	7.1	4.1
Mitigated*	3.7	31.7	21.7	0.03	3.5	2.3
Significance Threshold	**75**	**550**	**100**	**150**	**150**	**55**
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

Table 4.2-5
Peak Daily Construction Emissions at 11 Non-Refinery Facilities

Peak Daily Construction Emissions	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Unmitigated	40	349	239	0.4	78	45
Mitigated*	40	349	239	0.4	39	25
Significance Threshold	**75**	**550**	**100**	**150**	**150**	**55**
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

Refinery Facilities

There are nine refinery facilities subject to the NOx RECLAIM rules whose operators may choose to install NOx air pollution control equipment in response to the proposed project. These facilities include the following equipment/source categories: FCCUs, SRU/TGUs, coke calciner, refinery boilers and heaters, and refinery gas turbines. As summarized in Table 4.2-6, several types of NOx control technology may be installed on the various equipment/source categories operating at the nine affected refinery sector facilities.

Table 4.2-6

Estimated Number of NOx Control Devices to be Installed at 9 Refinery Facilities

Sector	Equipment/Source Category	Number of Affected Facilities*	Estimated Number of NOx Control Devices
Refinery	FCCUs	5	2 SCRs 2 LoTOx™ with WGSs* 1 LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	SRU/TGUs	5	5 LoTOx™ with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx™ with WGS or 1 UltraCat with DGS
		TOTAL	**84 SCRs** **8 LoTOx™ with WGSs** **1 LoTOx™ without WGS** **1 UltraCat DGS**

~~*~~ Note: While the total number of affected facilities for the refinery sector is nine, there is an overlap for all of the equipment/source categories except the petroleum coke calciner.

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

The overall objective of the proposed project is to reduce NOx emissions. However, in consideration of the complexity involved with operating FCCUs, SRU/TGUs, refinery boilers/heaters, coke calciners, and gas turbines, the equipment operators utilize a combination of various emission control equipment and techniques to control not only NOx, but other pollutants such as SOx, CO, PM10, PM2.5, and ammonia slip, as applicable, while maintaining overall efficiency. As there is no way to fully predict on a case-by-case basis what each facility operator will do to comply with the proposed project, the estimates in this CEQA analysis are based on the estimates provided in the ~~Preliminary~~ Draft Staff Report (which are based on information reported by the refineries in the survey and information from the control device manufacturers as well as the consultant reports prepared for each affected facility) combined with the assumptions applied in the previous CEQA documents which analyzed similar equipment in both the 2005 amendments to NOx RECLAIM and the 2010 amendments to SOx RECLAIM. Further, if a particular technology was identified as having a cost that exceeds $50,000 per ton, this CEQA analysis assumed that the facility operator would not install this type of air pollution control technology in response to the project.

For the purpose of conducting a worst-case analysis, 84 SCR units, eight LoTOx^{TM} with WGSs, one LoTOx^{TM} without a WGS, and one UltraCat DGS are assumed to be installed at the nine refinery sector facilities. In order to operate SCR and UltraCat technology, ammonia is necessary and, as such, tanks to store ammonia would also need to be installed. The size of each ammonia tank needed to operate the SCR units and one UltraCat filtration unit have been estimated to range between 2,000 and 11,000 gallons in capacity. The UltraCat filtration unit that was analyzed for the coke calciner would also need to utilize hydrated lime (Ca(OH)2) as an adsorbent. Further, three LoTOx^{TM} with WGSs for two FCCUs and one coke calciner may need to utilize sodium hydroxide (NaOH) to capture emissions. As such, tanks to store the hydrated lime and sodium hydroxide would also need to be installed.

Because the amount of plot space that may be needed to install one or more NOx control devices at any of the affected facilities would not exceed one acre, no more than one acre of area would need to be disturbed at a single facility at a given time. Construction was assumed to consist of two phases: 1) demolition; and 2) construction to install the air pollution control devices units along with supporting devices and structures. In addition, for facilities that will need to install tanks to store ammonia or sodium hydroxide, a site preparation phase was also included to account for building a containment berm as part of installing a storage tank.

A list of the anticipated construction equipment needed to install one SCR for either a refinery boiler/heater or refinery gas turbine at one refinery facility is presented in Table 4.2-7. A list of the anticipated construction equipment needed to install one SCR for one FCCU is presented in Table 4.2-8. Finally, a list of the anticipated construction equipment needed to install one scrubber, either WGS or DGS, for one refinery facility is presented in Table 4.2-9.

There are multiple source categories with multiple approaches to reducing NOx at the refinery facilities. With so many possibilities or permutations of how operators of the refinery could achieve actual NOx reductions, there is no way to predict what each facility operator will actually do. For this reason, the analysis illustrates the worst-case effects of applying the various NOx control technologies to each affected refinery facility. As a result, the construction emissions were calculated for each of the nine refineries.

From a construction point of view, the installation of a NOx control technology at a refinery is a complex process. For example, if a facility operator chooses to install NOx control equipment, time will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential control equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and scheduling contractors and workers. The amount of lead time can vary from six months (e.g., for a SCR for refinery/boiler heater or gas turbine) to up to 18 months for a scrubber (either a WGS or DGS).

Then to physically build the equipment, an additional six to 18 months would be needed. For example, six months would be needed to construct one SCR for one refinery boiler/ heater or gas turbine, 12 months would be needed to construct a SCR for a FCCU, and up to 18 months would be needed to construct a scrubber (either a WGS or DGS) for a FCCU or SRU/TGU. Where the new equipment will be sited will determine if any demolition activities would be required. For this analysis for a scrubber installation, to be conservative, one month of demolition activities is assumed to occur at each affected facility and an additional 17 months is assumed for site preparation, assembly and installation of the unit and ancillary support equipment, preparation of the affected unit for a turnaround/shutdown, and tying-in the new scrubber to the affected equipment.

Table 4.2-7

Construction Equipment Needed To Install 1 SCR for 1 Refinery Boiler/Heater/Gas Turbine

Off-Road Equipment Type	Amount	Daily Usage Hours
Rough Terrain Crane (28 ton)	1	8
Welders	2	8
Air Compressor	1	1
Backhoe	1	4
Plate Compactor	1	4
Forklift	1	3
Concrete Pump	1	2
Concrete Saw	1	2
Generator	1	8
Aerial Lift (Man lift)	1	2

Table 4.2-8

Construction Equipment Needed To Install 1 SCR For 1 FCCU

Off-Road Equipment Type	Amount	Daily Usage Hours
Crane	1	8
Rough Terrain Crane (28 ton)	1	8
Welders	5	8
Air Compressor	1	8
Backhoe	1	8
Plate Compactor	1	2
Forklift	1	6
Concrete Pump	1	2
Concrete Saw	1	2
Generator	2	8
Aerial Lift (Man lift)	2	2

Table 4.2-9

Construction Equipment Needed To Install 1 WGS or DGS At 1 Refinery Facility

Construction Phase	Off-Road Equipment Type	Amount	Daily Usage Hours
Demolition	Crane	1	8
Demolition	Front End Loader	1	8
Demolition	Forklift	1	8
Demolition	Concrete Saw	1	8
Demolition	Jack Hammer	1	8
Construction	Backhoe	1	8
Construction	Crane	2	8
Construction	Aerial Lift	3	8
Construction	Forklift	1	8
Construction	Generator	1	8
Construction	Welders	10	8
Construction	Cement Mixer	1	2

For any facility operator that plans to undergo construction to install NOx control equipment, and prior to receiving any permit to construct from the SCAQMD, a site-specific CEQA analysis in addition to this PEA may also be necessary depending on how much construction (i.e., demolition, site grading, etc.) would be involved and if the analysis varies from the assumptions in this document. For these reasons, the timing of constructing all of the possible NOx controls equipment is conservatively estimated to overlap for each refinery facility, at the earliest in 2016 because of the lead time that will be needed for most of types of NOx control projects contemplated in this PEA. This means that any on-road or off-road emission factors applied to calculate construction and operational impacts will conservatively be for equipment fleet year 2016 even though it is likely that all of the refinery facilities would begin construction activities well after 2016. While the NOx shave begins in 2016 with a four ton per year reduction in RECLAIM Trading Credits (RTCs), the available NOx RTCs continue to be reduced in two ton increments until 2022. In addition, the decision when construction would commence between 2016 and 2022 for refinery facilities in particular is also dependent upon the turnaround schedule of the affected equipment. Once construction of the control equipment is completed, it will need to be "tied-in" to the main equipment prior to start-up which typically occurs during a scheduled turnaround period.

To conduct a conservative "worst-case" analysis, this document examines the possibility that the facility operators will install NOx control equipment, including but not limited to exhaust stacks, cooling units, injection support equipment for catalyst, caustic, or sorbents including the associated storage vessels, associated piping designs, pumps, plus other ancillary equipment, as applicable. As a practical matter, construction activities that are anticipated to occur as a result of implementing the proposed project would likely occur prior to a scheduled maintenance (e.g., turnaround) of the affected unit.

Typically construction projects have staggered construction schedules which take into account design and engineering, ordering, purchasing and delivery of equipment, permitting and environmental review, the availability of construction crews, budgeting, and any other construction projects on site. However, due to wide range of construction time necessary to build the various types of NOx control equipment, the construction activities at other affected facilities could overlap. However, because of widely varying turnaround schedules of affected equipment within any given facility and based on past construction projects involving major construction equipment where the SCAQMD was the lead agency, the analysis in this PEA includes a conservative assumption that all of the refineries will have overlapping construction activities occurring in one year. However, since having all facilities construct all NOx controls within the first year is unlikely, for demonstrative purposes, the analysis also includes an analysis of the overlapping impacts spread out over a five- and seven-year period.

Table 4.2-10 presents the peak daily emissions from construction activities to install control equipment at each of the nine refinery facilities. To conduct a conservative analysis, overlapping construction activities were assumed to occur at all nine of the refinery facilities. Table 4.2-11 presents the peak daily emissions if construction spanning a five year period between 2016 and 2020 occurs at all nine refinery facilities. Finally, Table 4.2-12 presents the peak daily emissions if construction spanning a seven-year period between 2016 and 2022 occurs at all nine refinery facilities.

Table 4.2-10

Peak Daily Construction Emissions to Install Various NOx Control Equipment at 9 Refinery Facilities in the Same Year

Refinery Facility Number	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated* (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated* (lb/day)
1	56	338	209	0.41	274	~~156~~ 130	137	~~78~~ 65
2	36	233	104	0.20	30	30	12	12
3	8	42	42	0.08	98	~~50~~ 40	50	~~26~~ 21
4	44	275	146	0.28	128	~~81~~ 70	62	~~38~~ 33
5	72	449	270	0.65	326	~~184~~ 152	164	~~93~~ 78
6	66	404	250	0.55	324	~~183~~ 151	163	~~92~~ 77
7	16	83	84	0.17	148	~~77~~ 61	76	~~41~~ 33
8	48	296	167	0.33	177	~~106~~ 90	87	~~52~~ 44
9	44	275	146	0.28	175	~~104~~ 89	86	~~50~~ 42
Grand Total Over Same Year	**389**	**2,396**	**1,417**	**2.97**	**1,680**	**~~970~~ 814**	**838**	**~~483~~ 405**
Significance Threshold	75	550	100	150	150	150	55	55
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**

*Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.

Table 4.2-11
Peak Daily Construction Emissions to Install Various NOx Control Equipment at 9 Refinery Facilities Between 2016 and 2020

Refinery Facility Number	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated* (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated* (lb/day)
1	56	338	209	0.41	274	~~156~~ 130	137	~~78~~ 65
2	36	233	104	0.20	30	30	12	12
3	8	42	42	0.08	98	~~50~~ 40	50	~~26~~ 21
4	44	275	146	0.28	128	~~81~~ 70	62	~~38~~ 33
5	72	449	270	0.65	326	~~184~~ 152	164	~~93~~ 78
6	66	404	250	0.55	324	~~183~~ 151	163	~~92~~ 77
7	16	83	84	0.17	148	~~77~~ 61	76	~~41~~ 33
8	48	296	167	0.33	177	~~106~~ 90	87	~~52~~ 44
9	44	275	146	0.28	175	~~104~~ 89	86	~~50~~ 42
Peak Daily Emissions with One Year of Construction	**389**	**2,396**	**1,417**	**2.97**	**1,680**	**~~970~~ 814**	**838**	**~~483~~ 405**
Peak Daily Emissions with Five Years of Construction	**78**	**479**	**283**	**0.59**	**336**	**~~194~~ 163**	**168**	**~~97~~ 81**
Significance Threshold	75	550	100	150	150	150	55	55
Exceed Significance?	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

Table 4.2-12
Peak Daily Construction Emissions to Install Various NOx Control Equipment at 9 Refinery Facilities Between 2016 and 2022

Refinery Facility Number	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated* (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated* (lb/day)
1	56	338	209	0.41	274	~~156~~ 130	137	~~78~~ 65
2	36	233	104	0.20	30	30	12	12
3	8	42	42	0.08	98	~~50~~ 40	50	~~26~~ 21
4	44	275	146	0.28	128	~~81~~ 70	62	~~38~~ 33
5	72	449	270	0.65	326	~~184~~ 152	164	~~93~~ 78
6	66	404	250	0.55	324	~~183~~ 151	163	~~92~~ 77
7	16	83	84	0.17	148	~~77~~ 61	76	~~41~~ 33
8	48	296	167	0.33	177	~~106~~ 90	87	~~52~~ 44
9	44	275	146	0.28	175	~~104~~ 89	86	~~50~~ 42
Peak Daily Emissions with One Year of Construction	**389**	**2,396**	**1,417**	**2.97**	**1,680**	**~~970~~ 814**	**838**	**~~483~~ 405**
Peak Daily Emissions with Seven Years of Construction	**56**	**342**	**202**	**0.42**	**240**	**~~139~~ 116**	**120**	**~~69~~ 58**
Significance Threshold	75	550	100	150	150	150	55	55
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

Combined Construction Emissions From Non-Refinery and Refinery Facilities

As explained previously, due to the inability to predict if and when each operator of a non-refinery and a refinery facility alike would choose to install control equipment as a consequence to implementing the proposed project, the analysis conservatively assumes that construction activities within each of the non-refinery facilities and refinery facilities could overlap beginning in 2016.

Table 4.2-13 presents the peak daily emissions from construction activities to install control equipment at all 20 facilities (e.g., 11 non-refinery facilities plus 9 refinery facilities) and conservatively assumes that the overlapping construction activities will occur in the same year. However, since the operators of refinery facilities will need sufficient time to conduct advanced planning and financing for their capital improvement projects, it is likely that only minimal, if any, construction activities would occur at any refinery facilities during 2016. To account for the construction fluctuations that may occur, Tables 4.2-14 and 4.2-15 presents the peak daily emissions if construction occurs at all 20 facilities and spans a five year period between 2016 and 2020 and a seven-~~-~~year period between 2016 and 2022, respectively.

Table 4.2-13
Peak Daily Overlapping Non-Refinery and Refinery Construction Emissions
to Install Various NOx Control Equipment in Same Year

Sector Type	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated* (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated* (lb/day)
9 Refineries	389	2,396	1,417	2.97	1,680	~~970~~ 814	838	~~483~~ 405
11 Non-Refineries	40	349	239	0.4	78	39	45	25
Peak Daily Emissions with One Year of Construction	**429**	**2,745**	**1,656**	**3.37**	**1,758**	**~~1,009~~ 853**	**883**	**~~508~~ 430**
Significance Threshold	75	550	100	150	150	150	55	55
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

Table 4.2-14
Peak Daily Overlapping Non-Refinery and Refinery Construction Emissions
to Install Various NOx Control Equipment Between 2016 and 2020

Sector Type	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated* (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated* (lb/day)
9 Refineries	78	479	283	0.59	336	~~194~~ 163	168	~~97~~ 81
11 Non-Refineries	8	70	48	0.08	16	8	9	5
Peak Daily Emissions with Five Years of Construction	**86**	**549**	**331**	**0.67**	**352**	**~~202~~ 171**	**117**	**~~102~~ 86**
Significance Threshold	75	550	100	150	150	150	55	55
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

Table 4.2-15
Peak Daily Overlapping Non-Refinery and Refinery Construction Emissions to Install Various NOx Control Equipment Between 2016 and 2022

Sector Type	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated* (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated* (lb/day)
9 Refineries	56	342	202	0.42	240	~~139~~ 116	120	~~69~~ 58
11 Non-Refineries	6	50	34	0.06	11	6	6	4
Peak Daily Emissions with Seven Years of Construction	**62**	**392**	**236**	**0.48**	**251**	**~~145~~ 122**	**126**	**~~73~~ 62**
Significance Threshold	75	550	100	150	150	150	55	55
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**~~YES~~ NO**	**YES**	**YES**

**Mitigation includes standard fugitive dust controls applied pursuant to Rule 403.*

For the simultaneous construction of NOx control equipment at non-refinery and refinery facilities for construction all in the same year or for construction spread out over five years, the calculations show the total daily construction emissions exceed the SCAQMD's CEQA air quality significance thresholds for NOx, VOCs, CO, PM10, and PM2.5. For the simultaneous construction of NOx control equipment at non-refinery and refinery facilities for construction spread out over seven years, the calculations show the total daily construction emissions exceed the SCAQMD's CEQA air quality significance thresholds for NOx, PM10 (unmitigated), and PM2.5 (unmitigated and mitigated). Appendix E contains the spreadsheets with the results, assumptions, and methodologies used by the SCAQMD staff for this analysis.

With regard to odors, currently, for all diesel-fueled construction equipment and vehicles, the diesel fuel is required to have a low sulfur content (e.g., 15 ppm by weight or less) in accordance with SCAQMD Rule 431.2 – Sulfur Content of Liquid Fuels. Because the operation of the construction equipment for both non-refinery and refinery facilities will occur within the confines of existing affected facilities, sufficient dispersion of diesel emissions over distance generally occurs such that odors associated with diesel emissions may not be discernable to offsite receptors, depending on the location of the equipment and its distance relative to the nearest offsite receptor. Further, construction worker vehicles and delivery trucks onsite as a part of construction activities will not be allowed to idle longer than five minutes per any one location in accordance with the CARB idling regulation, so odors from these vehicles would not be expected. Thus, the proposed project is not expected to create significant adverse objectionable odors during construction. Since no significant impacts were identified for this issue, no mitigation measures for odors are necessary or required.

4.2.3.2 Construction Mitigation

The VOC, NOx, CO, PM10, and PM2.5 emissions for construction occurring in the same year and for construction spread out over five years exceed the applicable significance thresholds during construction. The NOx, PM10, and PM2.5 emissions for construction spread out over seven years also exceed the applicable significance thresholds during construction. As a result, the proposed project is expected to have significant adverse construction air quality impacts. If significant adverse environmental impacts are identified in a CEQA document, the CEQA document shall describe feasible measures that could minimize the significant adverse impacts (CEQA Guidelines §15126.4). Mitigation measures focus on the construction emissions of VOC, NOx, CO, PM10 and PM2.5 emissions. Therefore, feasible mitigation measures to reduce emissions associated with construction activities at the affected facilities are necessary to control emissions from heavy construction equipment and worker travel.

The following construction mitigation measures are required for each of the affected facilities whose operators choose to install NOx control equipment. If, at the time when each facility-specific project is proposed in response to the proposed project, SCAQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

<u>On-Road Mobile Sources</u>

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to SCAQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

<u>Off-Road Mobile Sources:</u>

AQ-2 Maintain construction equipment tuned to manufacturer's recommended specifications that optimize emissions without nullifying engine warranties.

AQ-3 The project proponent shall survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 For all construction areas that are demonstrated to be served by electricity, use electricity for on-site mobile equipment instead of diesel equipment to the extent feasible. For example, electric welders should be used in lieu of diesel or gasoline-fueled welders and onsite electricity should be used in lieu of temporary power generators. If electricity is not available, use alternative fuels where feasible.

AQ-5 ~~Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards~~

~~AQ-6~~ All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6~~7~~ Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts as defined in SCAQMD Rule 701.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

4.2.3.3 Remaining Construction Impacts After Mitigation

The air quality analysis concluded that significant adverse construction air quality impacts could be created by the proposed project because future construction activities, either for construction occurring in the same year or over a five year period, indicate that emissions from NOx, VOC, CO, PM10, and PM2.5 would exceed the SCAQMD's applicable significance thresholds for the respective pollutants. The air quality analysis also concluded that significant adverse construction air quality impacts could be created by the proposed project because future construction activities occurring over a seven-~~–~~year period indicate that emissions from NOx, PM10, and PM2.5 would exceed the SCAQMD's applicable significance thresholds for the respective pollutants.

Since it is expected that construction activities may occur as a consequence of implementing the proposed project, construction air quality impacts were concluded to be significant. In spite of implementing the above mitigation measures, construction air quality impacts would likely remain significant. Thus, because the proposed project overall has the potential to generate significant adverse air quality impacts for construction, even after applying mitigation, a Statement of Findings and a Statement of Overriding Considerations will be prepared for the Governing Board's consideration and approval prior to the public hearing for the proposed project.

4.2.3.4 Operation Analysis

Implementation of the proposed project is expected to result in direct air quality benefits from the reduction of 14 tons per day of NOx RTCs by 2022. Because of the RECLAIM market system, the actual reduction in NOx emissions each year may be less than the reduction in RTC holdings imposed by the project. However, emissions may be generated by the operation of the add-on air pollution control devices (as GHGs) due to increased electricity and water use, increased wastewater disposal, and amortized GHG emissions from construction. In addition, emissions of criteria pollutants and GHGs may be generated from offsite vehicles used for delivering fresh materials needed for operations (e.g., chemicals, fresh catalyst, etc.) and for hauling away solid waste for disposal or recycling (e.g., spent catalyst). Finally, since SCR technology utilizes ammonia, a Toxic Air Contaminant (TAC), some emissions of ammonia slip are expected for operation of SCR units.

Non-Refinery Facilities

The operation of each air pollution control device that may be installed at the 11 non-refinery facilities is not expected to generate criteria pollutant emissions but rather to lessen the amount of NOx generated by the existing equipment/emission sources. However, secondary criteria pollutant emissions are expected to be generated as part of operation activities associated with operating and maintaining the air pollution control equipment after it is installed. In particular, the following activities may be sources of secondary criteria pollutant emissions during operation: 1) vehicle trips via heavy-duty truck for periodic ammonia/urea deliveries for each SCR and Ultracat filtration unit installed; 2) vehicle trips via heavy-duty truck for periodic deliveries of absorbent, catalyst, and replacement filters as well as solid waste hauling of spent filters for each Ultracat filtration unit installed. A summary of these heavy-duty truck trips are presented in Table 4.2-16.

Table 4.2-16

Heavy-Duty Truck Trips at 11 Non-Refinery Facilities

Heavy-Duty Truck Trips	NH3/Urea Delivery Trips[1]	Adsorbent Delivery Trips [1,2]	Solid Waste Haul Trips[1]	Filter Waste Haul Trips[1]	Catalyst Delivery Trips[3]	Total Trips
Annual	437	5	11	1	11	465
Peak Daily	11	1	1	1	11	25

[1] Peak daily trips assumed one ammonia/urea delivery occurs at each non-refinery facility and adsorbent, solid waste and filter waste haul trips occurs on the same day.

[2] Adsorbent, solid waste and filter waste based on vendor estimates for SOx portion of Ultracat system.

[3] Only five catalyst delivery trips are expected because catalysts are replaced every two to three years.

Secondary operational emissions from the 11 non-refinery facilities were estimated using EMFAC2011 emission factors. In addition to heavy-duty truck trips, that analysis assumes that one medium-duty round-trip for control system maintenance personnel may be needed for each of the 11 non-refinery facilities. Based on the locations of disposal sites and ammonia suppliers relative to the locations of the affected facilities, default truck trip distances were assumed to be 80 miles round-trip, except that truck trip distances to deliver ammonia were assumed to be 100 miles round-trip.

As analyzed in Subchapter 4.3 (Energy), the add-on air pollution control devices anticipated to be installed pursuant to the proposed project will require electricity to operate. A total increase in energy demand of 45,344 kWh/day (or 45.3 MWh/day) for 11 non-refinery facilities (see Table 4.3-8 in Subchapter 4.3 – Energy) is estimated, thus requiring an increase in electricity generation from the electric generating utility local to the affected facility due to the proposed project. Because affected facilities are located throughout the SCAQMD jurisdiction, it is not possible to determine which specific utility will be impacted. However, utilities typically operate either combined cycle turbines (*assembly of heat engines that work in tandem from the same source of heat*) or simple cycle turbines (*one power cycle with no provision for waste heat recovery*). Because they are less efficient, the simple cycle turbine has higher emission factors so tend to generate higher criteria pollutant emissions. Thus, for a "worst-case" impact scenario and due to the unknown source of electricity generation, the simple cycle turbine emission factors (provided in the footnote to Table 4.2-17) are used to estimate criteria pollutant impact from operation of the air pollution control devices.

Secondary operational emissions from the non-refinery affected facilities are presented in Table 4.2-17.

Table 4.2-17
Peak Daily Operational Emissions from 11 Non-Refinery Facilities

Source	**No of Trips**	**Distance** (round trip miles/day)	**VOC** (lb/day)	**CO** (lb/day)	**NOx** (lb/day)	**SOx** (lb/day)	**PM10** (lb/day)	**PM2.5** (lb/day)
Heavy-Duty Truck	25	100	0.88	3.73	24.50	0.06	1.43	0.92
Medium-Duty Truck	11	80	0.29	1.40	8.58	0.02	0.37	0.23
Electric Generation[4]	--	--	0.91	3.63	4.08	--	2.72	2.69
		TOTAL	**2**	**9**	**37**	**0.07**	**5**	**4**
		Significance Threshold	55	550	55	150	150	55
		Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

As explained in Chapter 2 of this PEA, SCR and Ultracat filtration systems reduce NOx emissions by using ammonia, which is a toxic air contaminant (TAC). Unreacted ammonia emissions generated from these units are referred to as ammonia slip. Ammonia slip is limited to five parts per million (ppm) by permit condition. Based on the June 2015 Staff Report for SCAQMD Rule 1401.1 – Requirements for New and Relocated Facilities Near Schools, and SCAQMD Rule 1402 – Control of Toxic Air Contaminants from Existing Sources, the concentration at a receptor located 25 meters from a stack would be much less than one percent of the concentration at the release from the exit of the stack. Thus, the

4 Simple Cycle Turbine Emission Factors: NOx (0.09 lbs/MWh); CO (0.08 lbs/MWh); VOC (0.02 lbs/MWh); PM10 (0.06 lbs/MWh) - *Example Calculation*: NOx: 0.09 lbs/MWh x 45.3 MWh = 4.08 lbs

peak concentration of ammonia at a receptor located 25 meters from a stack is calculated by assuming a dispersion of one percent. While ammonia does not have an OEHHA approved cancer potency value, it does have non-carcinogenic chronic (200 µg/m^3) and acute (3,200 µg/m^3) reference exposure levels (RELs). Table 4.2-18 summarizes the calculated non-carcinogenic chronic and acute hazard indices for ammonia and compared these values to the respective significance thresholds; both were shown to be less than significant.

Table 4.2-18

Health Risk from the Non-Refinery Facilities Using Ammonia

Ammonia Slip Concentration at the Exit of the Stack (ppm)	**Peak Concentration at a Receptor 25 m from the Stack** (µg/m^3)	**Acute REL** (µg/m^3)	**Chronic REL** (µg/m^3)	**Acute Hazard Index**	**Chronic Hazard Index**
5	35	3,200	200	**0.01**	**0.17**
		Significance Threshold		**1.0**	**1.0**
		Exceed Significance?		**NO**	**NO**

Even if multiple SCRs are installed at one non-refinery facility, the locations of all the stacks would not be situated in the same place within the affected facility's property. As such, even with multiple SCR installations, the acute and chronic hazard indices would not be expected exceed the significance threshold.

The peak number of heavy-duty truck trips that may occur at one non-refinery facility (Facility 8) in one year is 149. Heavy-duty trucks are prohibited from idling for more than five minutes at any one location, but they can move to multiple locations and idle at each location for up to five minutes. Thus, for a conservative analysis, the analysis assumes that the trucks may idle for up to a total of 15 minutes per trip. Therefore, a peak of approximately 37 hours of idling may occur at one facility in one year. The CARB emission factor for an idling heavy-duty truck is 1.67 grams per hour of diesel particulate matter. Therefore, 6.88×10^{-5} ton of diesel particulate exhaust per year would be generated per year at an affected non-refinery facility. Based on the Tier II methodology described in the SCAQMD Risk Assessment Procedures for Rules 1401, 1401.1 and 212, Version 8.0 dated June 5, 2015, 6.88×10^{-5} ton of diesel particulate exhaust per year would generate a health risk of 1.5 in one million, which is less than the significance threshold of an increased probability of 10 cancer cases in one million.

<u>Refinery Facilities</u>

The operation of each air pollution control device that may be installed at the nine refinery facilities is also not expected to generate criteria pollutant emissions but rather to lessen the amount of NOx generated by the existing equipment/emission sources. However, as with the analysis for the non-refinery facilities, secondary criteria pollutant emissions are expected to be generated as part of operation activities associated with operating and maintaining the air pollution control equipment after it is installed. In particular, the following activities may be sources of secondary criteria pollutant emissions during operation: 1) vehicle trips via heavy-duty truck for periodic deliveries of ammonia for each

SCR installed, NaOH for three LoTOx™ WGSs installed, hydrated lime for two Ultracat DGSs installed, and oxygen for every LoTOx™ unit installed; 2) vehicle trips via heavy-duty truck for periodic deliveries of catalyst and replacement filters as well as solid waste hauling of spent filters for each SCR unit installed; and 3) via heavy-duty truck hauling solid waste generated by each scrubber (WGS and DGS) installed. A summary of these heavy-duty truck trips are presented in Table 4.2-19.

Table 4.2-19

Heavy-Duty Operational Truck Trips at 9 Refinery Facilities

	Number of Heavy-Duty Truck Trips								
	NH3[1]	**NaOH[1]**	**Hydrated Lime[1]**	**Soda Ash[1]**	**Oxygen [1]**	**Fresh Catalyst[2]**	**Solid Waste[1]**	**Spent Catalyst[2]**	**TOTAL**
Annual	498	56	26	21	44	49	96	49	839
Peak Daily	17	3	1	4	1	16	7	16	65

[1] Peak daily trips assumed one heavy-duty truck trip occurs at each refinery facility for each chemical delivery or waste/spent catalyst haul trip.

[2] SCR fresh catalyst delivery trips are expected when the SCR is first built and then replaced every five years. Similarly, spent catalyst waste is also generated every five years.

Secondary operational emissions from the nine refinery facilities were estimated using EMFAC2011 emission factors. Based on the locations of disposal sites and chemical suppliers relative to the locations of the affected refineries, default round-trip truck distances were assumed to be: 1) 200 miles for solid waste hauling; 2) 50 miles for soda ash deliveries; 3) 100 miles for ammonia deliveries; 4) 100 miles for fresh catalyst deliveries; 5) 100 miles for spent catalyst hauling; 6) 66.2 miles for hydrated lime deliveries; 7) 50 miles for NaOH deliveries; and, 8) 50 miles for oxygen deliveries.

As previously discussed for non-refinery facilities, Subchapter 4.3 (Energy) analyzed potential energy demand from the operation of add-on air pollution control devices anticipated to be installed pursuant to the proposed project. A total increase in energy demand for 9 refinery facilities is 168,170 kWh/day (or 168.2 MWh/day) (see Table 4.3-7 in Subchapter 4.3 – Energy), thus requiring an increase in electricity generation from the local power plants servicing the affected facilities due to the proposed project. Because affected facilities are located throughout the SCAQMD jurisdiction, it is not possible to determine which specific utility will be impacted. Similar to the calculations conducted for the non-refinery facilities (see Table 4.2-17), the simple cycle turbine emission factors (see footnote for Table 4.2-20) are used to estimate criteria pollutant impact from the operation of the air pollution control devices at the 9 refinery facilities because simple cycle turbine emission factors are higher than combined cycle turbine emission factors. By doing so, the air quality analysis is based on a "worst-case" impact scenario.

Secondary operational emissions from the refinery affected facilities are presented in Table 4.2-20.

Table 4.2-20
Peak Daily Operational Emissions from 9 Refinery Facilities

Vehicle Type	**No of Trips**	**Distance** (round trip miles/day)	**VOC** (lb/day)	**CO** (lb/day)	**NOx** (lb/day)	**SOx** (lb/day)	**PM10** (lb/day)	**PM2.5** (lb/day)
Heavy-Duty Truck	65	8,166	11.86	53.12	138.04	0.33	6.93	5.69
Electric Generation[5]	--	--	3.36	13.45	15.14	--	10.09	9.89
		TOTAL	**15**	**67**	**153**	**0**	**17**	**16**
		Significance Threshold	55	550	55	150	150	55
		Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**

Emission sources associated with the operational-related activities as a result of implementing the proposed project may emit toxic air contaminants (TACs). For example, as explained in Chapter 2 of this PEA, SCR and Ultracat filtration systems reduce NOx emissions by using ammonia, which is a TAC. Unreacted ammonia emissions generated from these units are referred to as ammonia slip. Ammonia slip is limited to five parts per million (ppm) by permit condition. Based on the June 2015 Staff Report for SCAQMD Rule 1401.1 – Requirements for New and Relocated Facilities Near Schools, and SCAQMD Rule 1402 – Control of Toxic Air Contaminants from Existing Sources, the concentration at a receptor located 25 meters from a stack would be much less than one percent of the concentration at the release from the exit of the stack. Thus, the peak concentration of ammonia at a receptor located 25 meters from a stack is calculated by assuming a dispersion of one percent. While ammonia does not have an OEHHA approved cancer potency value, it does have non-carcinogenic chronic (200 $\mu g/m^3$) and acute (3,200 $\mu g/m^3$) reference exposure levels (RELs). Table 4.2-21 summarizes the calculated non-carcinogenic chronic and acute hazard indices for ammonia and compared these values to the respective significance thresholds; both were shown to be less than significant.

Table 4.2-21
Health Risk from Refinery Facilities Using Ammonia

Ammonia Slip Concentration at the Exit of the Stack (ppm)	**Peak Concentration at a Receptor 25 m from the Stack** ($\mu g/m^3$)	**Acute REL** ($\mu g/m^3$)	**Chronic REL** ($\mu g/m^3$)	**Acute Hazard Index**	**Chronic Hazard Index**
5	35	3,200	200	**0.01**	**0.2**
		Significance Threshold		**1.0**	**1.0**
		Exceed Significance?		**NO**	**NO**

[5] Simple Cycle Turbine Emission Factors: NOx (0.09 lbs/MWh); CO (0.08 lbs/MWh); VOC (0.02 lbs/MWh); PM10 (0.06 lbs/MWh) - *Example Calculation*: NOx: 0.09 lbs/MWh x 168.2 MWh = 15.14 lbs

Even if multiple SCRs are installed at one refinery facility, the locations of all the stacks would not be situated in the same place within the affected facility's property. As such, even with multiple SCR installations, the acute and chronic hazard indices would not be expected exceed the significance threshold.

In addition, diesel particulate matter from the exhaust of diesel-fueled heavy duty trucks is also a TAC. The analysis estimates that a peak of 147 heavy-duty truck trips may occur at a single facility in one year (e.g., at Facility 6). Heavy-duty trucks are expected to idle for up to 15 minutes per trip. Therefore, up to 37 hours of idling may occur at a single facility. The CARB emission factor for an idling heavy-duty truck is 1.67 grams per hour of diesel particulate matter. Therefore, a peak of 6.78×10^{-5} ton of diesel particulate exhaust per year would be generated at one refinery facility. Based on the Tier II methodology described in the SCAQMD Risk Assessment Procedures for Rules 1401, 1401.1 and 212, Version 8.0 dated June 5, 2015, 6.78×10^{-5} ton of diesel particulate exhaust per year would generate a health risk of 1.5 in one million, which is less than the significance threshold of an increased probability of 10 cancer cases in one million.

Lastly, caustic may be used in the operation of three WGSs. With the potential for the installation of eight WGSs that utilize caustic, a maximum of eight caustic storage tanks may be installed. There are several types of caustic solutions that can be used in WGS operations, but sodium hydroxide (NaOH) is the most commonly used. Due to facility-specific information about their respective processes, three facilities are estimated to install three WGSs (one each) that utilize NaOH. NaOH is a TAC that is a non-cancerous but acutely hazardous substance. For "worst-case" operations, 5.84 tons per day of NaOH (50 percent solution, by weight) is estimated to be needed to operate three WGSs. Again, due to facility-specific information about their respective processes, the remaining five of the eight facilities that were assumed to install WGSs were projected to have an increased demand in caustic that is made of sodium carbonate (Na2CO3) which is commonly known as soda ash, a non-toxic, non-cancerous, and non-hazardous substance.

Even though the facilities that may be affected by the proposed project may already use NaOH elsewhere in their facilities, for the purpose of conducting a "worst-case" construction analysis, one 10,000 gallon storage tank for caustic solution was assumed to be constructed for each WGS installed. Thus, for three WGSs, three 10,000 gallon NaOH storage tanks was assumed to be constructed. As summarized in Table 4.2-22, for each facility that was projected to increase the use in the acutely hazardous substance NaOH, the filling loss and the working loss of each NaOH tank were calculated, added together, and that sum was compared to the most stringent Rule 1401 Screening Emission Level for NaOH (0.004 pounds per hour at the nearest receptor distance of 25 meters).

Table 4.2-22
Summary of Filling and Working Losses for NaOH Storage Tanks

Facility ID	Projected Increase in NaOH Demand (tons/day)	A: Hourly NaOH (as PM10) Filling Loss (lb/hr)	B: Hourly NaOH (as PM10) Working Loss (lb/hr)	A + B = Total Hourly NaOH (as PM10) Losses (lb/hr)	NaOH Acute Screening Level at 25 meters (lb/hr)	Do Total Hourly Losses Exceed Acute Screening Level For NaOH? (Yes/No)	Significant?
2	3.37	7.60E-04	2.28E-03	3.04E-03	4.00E-03	NO	NO
4	0.45	1.01E-04	3.04E-04	4.06E-04	4.00E-03	NO	NO
9	2.02	4.57E-04	1.37E-03	1.83E-03	4.00E-03	NO	NO
Total	**5.84**						

None of the total hourly loss projections exceeded the acute screening level for NaOH for any of the affected facilities. It is important to note that the toxics analysis is a localized analysis and because of the distances between the affected facility locations, the NaOH emission impacts would not overlap. Thus, because the screening level for NaOH was not exceeded for either of the affected facilities, no significant air quality operational impacts with respect to the use of NaOH are expected from the proposed project. NaOH is not classified as a carcinogen, so a cancer risk analysis was not performed.

Combined Operation Emissions From Both Non Refinery and Refinery Facilities

Table 4.2-23 presents the peak daily emissions from operating control equipment at all 20 facilities (e.g., 11 non-refinery facilities plus nine refinery facilities) at full build out.

Table 4.2-23
Peak Daily Overlapping Non-Refinery and Refinery Emissions
from Operating Various NOx Control Equipment in Same Year

Operation Activity	**VOC** (lb/day)	**CO** (lb/day)	**NOx** (lb/day)	**SOx** (lb/day)	**PM10** (lb/day)	**PM2.5** (lb/day)
Delivery and Haul Trips at 11 Non-Refineries	1.17	5.13	33.10	0.07	1.80	1.14
Delivery and Haul Trips at 9 Refineries	11.86	53.12	138.04	0.33	6.93	5.69
Electricity Generation (for 11 Non-Refineries)	0.91	3.63	4.08	--	2.72	2.69
Electricity Generation (for 9 Non-Refineries)	3.36	13.45	15.14	--	10.09	9.89
Benefit from NOx Control Equipment*	0	0	-17,540 ~~17,580~~	0	0	0
TOTAL	**17**	**75**	**-17,350 ~~17,390~~**	**0.4**	**22**	**19**
Significance Threshold	55	550	55	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

* A negative number denotes an emission *reduction* (or benefit to air quality)

The calculations show the total daily operation emissions due to delivery and haul trips and electricity generation exceed the SCAQMD's CEQA air quality significance threshold of 55 pounds of NOx per day. However, because there will be an overall reduction in NOx emissions of 8.77~~8.79~~ tons per day (or ~~17,580~~ 17,540 pounds ~~lbs~~ per day) during the operational phase due to the operation of NOx air pollution control equipment, the net NOx emissions impact will result in an overall reduction in NOx emissions creating an air quality benefit. Appendix E contains the spreadsheets with the results, assumptions, and methodologies used by the SCAQMD staff for this analysis.

With regard to odors currently, for all diesel-fueled vehicles that may be utilized during operation activities at both non-refinery and refinery facilities, the diesel fuel is required to have a low sulfur content (e.g., 15 ppm by weight or less) in accordance with SCAQMD Rule 431.2 – Sulfur Content of Liquid Fuels. Because the deliveries of supplies and the removal of solid waste for both non-refinery and refinery facilities will occur within the confines of existing affected facilities, sufficient dispersion of diesel emissions over distance generally occurs such that odors associated with diesel emissions may be discernable to offsite receptors, depending on the location of the equipment and its distance relative to the nearest offsite receptor. Further, the use of diesel-fueled trucks as part of operation activities will not be allowed to idle longer than fifteen minutes at the affected facilities once onsite, so odors from these vehicles would not be expected. Thus, the proposed project is not expected to create significant adverse objectionable odors during operation. Since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

4.2.3.5 Operation Mitigation

The analysis indicates that there will be an overall reduction in NOx emissions during the operational phase of the proposed project. Further, no other pollutant emissions exceed the applicable significance thresholds during operation for the proposed project. Thus, because there are no significant adverse air quality impacts with the operational phase of the proposed project, no air quality mitigation measures are required.

4.2.3.6 Remaining Operation Impacts After Mitigation

The air quality analysis concluded that potential operational air quality impacts would be less than significant, no mitigation measures were required, so operational air quality impacts remain less than significant.

4.2.4 Cumulative Air Quality Impacts

In general, the preceding analysis concluded that air quality impacts from construction activities would be significant from implementing the proposed project because the SCAQMD's significance thresholds for construction will be exceeded before mitigation for VOC, NOx, CO, PM10, and PM2.5. After mitigation, VOC, NOx, CO, PM10, and PM2.5emissions will also exceed the SCAQMD's significance thresholds for construction. Thus, the air quality impacts due to construction are considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, generate significant adverse cumulative air quality impacts. It should be noted, however, that the air quality analysis is a conservative, "worst-case" analysis so the actual construction impacts are not expected to be as great as estimated here. Further, the construction activities are temporary when compared to the permanent projected long-term emission reductions of NOx as a result of the proposed project.

The analysis also indicates that, in addition to the overall reduction in NOx emissions, the proposed project will result in less than significant increases of VOC, CO, NOx, PM10 and PM2.5 emissions during the operational phase of the proposed project. Because operational emissions do not exceed the project-specific air quality significance thresholds, which also serve as the cumulative significance thresholds, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)). Further, the amount of emission reductions to be achieved by the proposed project for NOx will, at the very least, meet the emission reduction projections and commitments made in the AQMP. Even though the proposed project will cause a temporary and significant adverse increase in air emissions during the construction phase and less than significant increases in air emissions during the operation phase, the temporary net increase in construction emissions combined with the total permanent emission reductions projected overall during operation would not interfere with the air quality progress and attainment demonstration projected in the AQMP. Further, based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, is anticipated to bring the District into attainment with all national and most state ambient air quality standards by the year 2023. Therefore, cumulative operational air quality impacts from the proposed project, previous amendments and all other AQMP control measures considered together, are not expected to be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement. This determination is consistent with the conclusion in the 2012 AQMP Final Program EIR that cumulative air quality impacts from all AQMP control measures are not expected to be significant (SCAQMD, 2012). Therefore, there will be no significant cumulative adverse operational air quality impacts from implementing the proposed project.

Though the proposed project involves combustion processes which could generate GHG emissions such as CO2, CH4, and N2O, the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs or PFCs. Relative to GHGs, implementing the proposed project is expected to increase GHG emissions that exceed the SCAQMD's GHG significance threshold for industrial sources. In addition, implementing the proposed project is expected to generate significant adverse cumulative GHG air quality impacts. The GHG analysis for the proposed project can be found in the Section 4.2.6 – Greenhouse Gas Impacts.

4.2.5 Cumulative Mitigation Measures

The analysis indicates that, in addition to the overall reduction in NOx emissions, the proposed project will result in less than significant increases of VOC, CO, NOx, PM10 and PM2.5 emissions during the operational phase of the proposed project. However, no pollutant emissions exceed the applicable significance thresholds during operation for the proposed project. Thus, there are no adverse significant cumulative air quality impacts with the operational phase of the proposed project and as such, no cumulative mitigation measures for operation are required.

The analysis also indicates that the VOC, NOx, CO, PM10, and PM2.5 emissions will exceed the applicable significance thresholds during construction. As a result, the proposed project is expected to have significant cumulative adverse construction air quality impacts. Mitigation measures that focus on the VOC, NOx, CO, PM10, and PM2.5 emissions that may be generated during construction are required to minimize the significant air quality impacts associated with construction activities. Therefore, feasible mitigation measures to reduce emissions associated with construction activities at the affected facilities are necessary to control emissions from heavy construction equipment and worker travel. While the mitigation measures may reduce emissions associated with construction activities at the affected facilities to the maximum extent feasible, none will avoid the significant impact or reduce the impact to less than significant.

The following construction mitigation measures are required for each of the affected facilities whose operators choose to install NOx control equipment. If, at the time when each facility-specific project is proposed in response to the proposed project, SCAQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

<u>On-Road Mobile Sources</u>

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to SCAQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

<u>Off-Road Mobile Sources:</u>

AQ-2 Maintain construction equipment tuned to manufacturer's recommended specifications that optimize emissions without nullifying engine warranties.

AQ-3 The project proponent shall survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 For all construction areas that are demonstrated to be served by electricity, use electricity for on-site mobile equipment instead of diesel equipment to the extent feasible. For example, electric welders should be used in lieu of diesel or gasoline-fueled welders and onsite electricity should be used in lieu of temporary power generators. If electricity is not available, use alternative fuels where feasible.

AQ-5 ~~Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards~~

~~AQ-6~~ All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6~~7~~ Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

4.2.6 Greenhouse Gas Impacts

Significant changes in global climate patterns have recently been associated with global warming, an average increase in the temperature of the atmosphere near the Earth's surface, attributed to accumulation of GHG emissions in the atmosphere. GHGs trap heat in the atmosphere, which in turn heats the surface of the Earth. Some GHGs occur naturally and are emitted to the atmosphere through natural processes, while others are created and emitted solely through human activities. The emission of GHGs through the combustion of fossil fuels (i.e., fuels containing carbon) in conjunction with other human activities, appears to be closely associated with global warming. State law defines GHG to include the following: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) (HSC §38505(g)). The most common GHG that results from human activity is CO2, followed by CH4 and N2O.

Traditionally, GHGs and other global warming pollutants are perceived as solely global in their impacts and that increasing emissions anywhere in the world contributes to climate change anywhere in the world. A study conducted on the health impacts of CO2 "domes" that form over urban areas cause increases in local temperatures and local criteria pollutants, which have adverse health effects[6].

The analysis of GHGs is a different analysis than the analysis of criteria pollutants for the following reasons. For criteria pollutants, the significance thresholds are based on daily emissions because attainment or non-attainment is primarily based on daily exceedances of applicable ambient air quality standards. Further, several ambient air quality standards are based on relatively short-term exposure effects on human health (e.g., one-hour and eight-hour standards). Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs occur over a longer term which means they affect the global climate over a relatively long time frame. As a result, the SCAQMD's current position is to evaluate the effects of GHGs over a longer timeframe than a single day (i.e., annual emissions). GHG emissions are typically considered to be cumulative impacts because they contribute to global climate effects. GHG emission impacts from implementing the proposed project were calculated at the project-specific level during construction and operation. For example, installation of NOx control equipment has the potential to increase the use of electricity, fuel, and water and the generation of wastewater which will in turn increase CO2 emissions.

The SCAQMD convened a "Greenhouse Gas CEQA Significance Threshold Working Group" to consider a variety of benchmarks and potential significance thresholds to evaluate GHG impacts. On December 5, 2008, the SCAQMD adopted an interim CEQA GHG Significance Threshold for projects where SCAQMD is the lead agency (SCAQMD, 2008). This interim threshold is set at 10,000 metric tons of CO2 equivalent emissions (MTCO2eq) per year. The SCAQMD prepared a "Draft Guidance Document – Interim CEQA GHG Significance Thresholds" that outlined the approved tiered approach to determine GHG significance of projects (SCAQMD, 2008, pg. 3-10). The first two tiers involve: 1) exempting the project because of potential reductions of GHG emissions allowed under CEQA; and, 2) demonstrating that the project's GHG emissions are consistent with a local general plan. Tier 3 proposes a limit of 10,000 MTCO2eq per year as the incremental increase representing a significance threshold for projects where SCAQMD is the lead agency (SCAQMD, 2008, pg. 3-11). Tier 4 (performance standards) is yet to be developed. Tier 5 allows offsets that would reduce the GHG impacts to below the Tier 3 brightline threshold. Projects with incremental increases below this threshold will not be cumulatively considerable.

As indicated in Chapter 3, combustion processes generate GHG emissions in addition to criteria pollutants. The following analysis mainly focuses on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. CO2 emissions were estimated using emission factors from CARB's EMFAC2011 and OFFROAD2011 models and USEPA's AP-42.

[6] Jacobsen, Mark Z. "Enhancement of Local Air Pollution by Urban CO2 Domes," Environmental Science and Technology, as describe in Stanford University press release on March 16, 2010 available at: http://news.stanford.edu/news/2010/march/urban-carbon-domes-031610.html.

In addition, CH4 and N20 emissions were also estimated and are included in the overall GHG calculations. No other GHGs are expected to be emitted because the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs or PFCs.

Installation of NOx control equipment as part of implementing the proposed project is expected to generate construction-related CO2 emissions. In addition, based on the type and size of equipment affected by the proposed project, CO2 emissions from the operation of the NOx control equipment are likely to increase from current levels due to using electricity, fuel and water and generating more wastewater. The proposed project will also result in an increase of GHG operational emissions produced from additional truck hauling and deliveries necessary to accommodate the additional solid waste generation and increased use of chemicals and supplies.

For the purposes of addressing the potential GHG impacts of the proposed project, the overall impacts of CO2e emissions from the project were estimated and evaluated from the earliest possible initial implementation of the proposed project with construction beginning in 2016. Once the proposed project is fully implemented, the potential NOx emission reductions would continue through the end of the useful life of the equipment. The analysis estimated CO2e emissions from all sources subject to the proposed project (construction and operation) from the beginning of the proposed project (2016) to the end of the project (2022). The beginning of the proposed project was assumed to be no sooner than 2016, since installing NOx control equipment takes considerable advance planning and engineering. Full implementation of the proposed project is expected to occur by the end of 2022 when the entire 14 tons per day of the NOx RTC shave is completed such that any installed or modified NOx controls could be constructed and operational by this final date. Thus, once construction is complete and the equipment is operational, CO2e emissions will remain constant.

GHG emissions from the 11 non-refinery and nine refinery facilities were quantified by applying the same assumptions used to quantify the criteria pollutant emissions. The only exception is that the construction GHG emissions were amortized over a 30-year project life in accordance with the guidance provided in the Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans[7] that was adopted by the SCAQMD Governing Board in December 2008.

For the non-refinery facilities, approximately 325 amortized[8] metric tons per year (MT/year) of GHGs (as carbon dioxide equivalent emissions or CO2e) would be generated from construction-related activities that may occur at the affected non-refinery facilities in response to implementing the proposed project. Similarly, approximately 77 MT/year of GHG emissions would be generated from operation-related activities (e.g., truck trips) that may occur at the non-refinery facilities in response to implementing the proposed project. The generation of electricity needed to operate the air pollution control devices is calculated based on the assumption a simple

[7] Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans, http://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgattachmente.pdf?sfvrsn=2

[8] To amortize GHGs from temporary construction activities over a 30-year period (*est. life of the project/ equipment*), the amount of CO2e emissions during construction are calculated and then divided by 30.

cycle turbine is increasing operation to fulfill additional demand. Simple cycle turbines have higher emission factors than combined cycle turbines so the results are more "worst case." Based on the energy needs from non-refinery facilities at 45.3 MWh/day (see Table 4.3-8 in Subchapter 4.3 – Energy), the GHG emissions from electric generation is 7,866 MT/year[9]. It should be noted that unlike refinery facilities, the control equipment at non-refinery facilities do not generate water demand or wastewater, thus are not included in the GHG calculations.

In total, 8,268 MT/year of GHG emissions would be generated by construction and operation activities at the 11 non-refinery facilities, should these facility operators choose to install NOx control technology in response to the proposed project. The total amount of GHG emissions that may be generated from operation activities at all affected non-refinery facilities is less than the GHG significance threshold of 10,000 MT/year.

In addition, for the nine refinery facilities, approximately 1,373 amortized MT/year of GHGs as CO2e would be generated from construction-related activities that may occur at the affected refinery facilities in response to implementing the proposed project. Similarly, approximately 194 MT/year of GHG emissions would be generated from operation-related activities (e.g., truck trips) that may occur at the refinery facilities in response to implementing the proposed project. Further, because WGSs utilize water and generate wastewater during operation, GHG emissions may be created from the increased use of water and the increased generation of wastewater from WGS operation activities. As such, approximately 813 MT/yr of CO2e from increased water use and 319 MT/year of CO2e from increased wastewater generation would be expected if WGSs are installed and operated as a result of implementing the proposed project. Lastly, because operation of all of the NOx control technologies require electricity, approximately 30,818 MT/year of CO2e may be generated if all refinery facilities install NOx control equipment. In total, 33,517 MT/year of CO2e emissions would be generated by construction and operation activities occurring at the nine refinery facilities, should these facility operators choose to install NOx control technology in response to the proposed project. The total amount of GHG emissions that may be generated from operation activities at refinery facilities is greater than the GHG significance threshold of 10,000 MT/year and thus, would be considered a significant adverse GHG emissions impact.

Table 4.2-24 summarizes the unmitigated CO2e impacts from both construction activities and operation activities per refinery facility.

[9] Simple cycle turbine GHG emission factor: 1,049 lbs/MWhr
Calculation: 1,049 lbs/MWhr x 45.3 MWhr/day x 365 days/year ÷ 2,205 MT/lbs = 7,866 MT/year

Table 4.2-24
Overall Unmitigated CO2e Increases Due to Construction
and Operation Activities per Refinery Facility (metric tons/year)[1]

Refinery Facility ID	Temporary Construction Activities (diesel and gasoline fuel use)[2] (MT/yr)	Operational Electricity Use (MT/yr)	Operational Water Use/ Conveyance (MT/yr)	Operational Wastewater Generation (MT/yr)	Operational Truck Trips (diesel fuel use) (MT/yr)	Total CO2e (MT/yr)
1	313	7,522	94	19	26	7,974
2	82	2,116	55	23	12	2,288
3	31	296	0	0	2	329
4	97	4,582	66	30	14	4,789
5	363	4,504	295	133	37	5,332
6	181	3,984	148	66	35	4,414
7	85	1,487	0	0	16	1,588
8	85	2,605	94	19	19	2,822
9	136	3,723	59	30	32	3,980
TOTAL	**1,373**	**30,818**	**813**	**319**	**194**	**33,517**

[1] 1 metric ton = 2,205 pounds
[2] GHGs from temporary construction activities are amortized over 30 years.

It is important to note that none of the affected facilities individually exceed the industrial GHG significance threshold of 10,000 MT/day. However, the GHG emissions from the refinery sector exceed the threshold and therefore, the proposed project is considered to have adverse significant GHG impacts for the refinery sector.

After combining the GHG emissions from the non-refinery and refinery sectors, in total, 41,785 MT/year of CO2e emissions would be generated by construction and operation activities occurring at all 11 of the non-refinery facilities and nine refinery facilities, should these facility operators choose to install NOx control technology in response to the proposed project. Thus, the overall GHG emissions from combining both sectors exceed the GHG significance threshold and therefore, the proposed project is considered to have significant adverse GHG impacts.

Because the proposed project is expected to generate construction-related CO2 emissions, and the operational phase of the proposed project is also expected to generate additional GHG emissions, adverse significant GHG cumulative impacts from the proposed project are expected. If significant adverse environmental impacts are identified in a CEQA document, the CEQA document shall describe feasible measures that could minimize the significant adverse impacts (CEQA Guidelines §15126.4). Mitigation measures focus on the GHG emissions. Therefore, feasible mitigation measures to reduce GHG emissions at the affected facilities are necessary.

4.2.7 Greenhouse Gas Mitigation Measures

If the proposed project is implemented, the analysis indicates that there will be a significant increase in GHG emissions. Because adverse significant GHG impacts are expected from the proposed project, feasible GHG mitigation measures are required. While none of the affected facilities individually exceed the industrial GHG significance threshold of 10,000 MT/day, individual facilities may be able to offset their increases in GHG emissions through CARB's AB 32 cap-and-trade program. Cap-and-trade is a market-based regulation that is designed to reduce GHGs from multiple sources by setting a firm limit or cap on GHGs and minimize the compliance costs of achieving AB 32 goals. The cap will decline approximately three percent each year from 2015 to 2020. Every year, facilities in the cap-and-trade program turn in allowances and offsets for 30 percent of previous year's GHG emissions. Also, for each compliance period, facilities in the cap-and-trade program turn in allowances and a limited number of offsets to cover the remainder of emissions in that compliance period. Finally, if the compliance deadline is missed or there is a shortfall, four allowances must be provided for every ton of emissions that was not covered in time. All nine refineries and 10 out of the 11 non-refinery facilities that may be affected by the proposed project are in the CARB's AB 32 cap-and-trade program for GHGs, so their GHG emissions, including any individual facility increases from the proposed project would be covered under that program.

For the one facility that is not in CARB's AB 52 cap-and-trade program (e.g., Facility 9), GHG emissions could potentially be mitigated through purchasing reductions via SCAQMD Regulation XXVII – Climate Change, which created the SoCal Climate Solutions Exchange. The SoCal Climate Solutions Exchange is a voluntary program where facilities in the district can undertake projects to voluntarily reduce GHG emissions in advance of any regulatory requirement. GHG mitigation measures for industrial sources are under development but there are some existing GHG reducing protocols that have been approved or adopted by various organizations and some of these are already used in the SCAQMD's SoCal Climate Solutions Exchange. In order to participate in the exchange, the GHG reductions need to be real, additional (surplus), quantifiable, verifiable, permanent over a specific time, and enforceable. These early reductions can be helpful to facilities that would need offsets for GHG mitigation.

In addition, the California Climate Action Registry (CCAR) is currently developing the following protocols: 1) bus rapid transit; 2) blended cement; 3) tidal wetland sequestration (farms converting to wetlands). CCAR is also evaluating several categories for potential protocol development, including waste diversion, local government operations, boiler efficiency; and truck stop electrification. CCAR has been asked to look at other areas, such as waste water biogas, natural gas pipelines, agricultural soil sequestration, and CO2 capture and storage, and those will be evaluated in the future.

In addition, the California Air Pollution Control Officers Association (CAPCOA) has suggested that lead agencies develop a "Green List of Projects" (Green List) to be consistent with and achieve the goals of AB 32 and to encourage projects that can provide overall GHG emission reduction benefits. Of the Green List projects, especially in consideration that compliance with the proposed project could result in the installation of water-intensive scrubbers, recycled water projects and the utilization of recycled water seem to be among the most direct ways to mitigate GHG emissions for the proposed project. Specifically, the energy it would take to treat and convey reclaimed water to a facility (e.g., 1,200 kWh/MMgallons[10]) is approximately 10 times less than the amount of energy it would take for potable water (e.g., 12,700 kWh/MMgallons[11]) to be supplied, conveyed and distributed. Thus, for each facility that will have future access to recycled water and uses reclaimed wastewater to satisfy the water demands for the proposed project and in turn, mitigate CO2eq emissions, less GHG emissions would be generated for the operational water use/conveyance and operational wastewater generation portions of the proposed project.

Based on the preceding discussion, the following mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. If, at the time when each facility-specific project is proposed in response to the proposed project, SCAQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

GHG-1 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

GHG-2 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required ~~to use their best efforts~~ to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be supplied to the project.

Tables 4.2-25 summarizes the mitigated CO2e impacts from both construction activities and operation activities per refinery facility and shows that if mitigation for water and wastewater is applied to Refineries 1, 5 and 6 should they utilize recycled water, a savings of GHG emissions of 685 MT/year may occur. It is important to note that none of the NOx control equipment contemplated for the non-refinery sector utilize water or would generate wastewater. Thus, utilizing recycled water to mitigate GHG emissions from the proposed project would only apply to certain refinery facilities whose operators choose to install NOx control equipment that utilize water (e.g., WGSs).

[10] California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[11] California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

Table 4.2-25
Overall Mitigated CO2e Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1]

Refinery Facility ID	**Temporary Construction Activities (diesel and gasoline fuel use)[2]** (MT/yr)	**Operational Electricity Use** (MT/yr)	**Operational Water Use/ Conveyance** (MT/yr)	**Operational Wastewater Generation** (MT/yr)	**Operational Truck Trips (diesel fuel use)** (MT/yr)	**Total CO2e** (MT/yr)
1	313	7,522	9	2	26	7,872
2	82	2,116	55	23	12	2,288
3	31	296	0	0	2	329
4	97	4,582	66	30	14	4,789
5	363	4,504	28	13	37	4,945
6	181	3,984	14	6	35	4,220
7	85	1,487	0	0	16	1,588
8	85	2,605	94	19	19	2,822
9	136	3,723	59	30	32	3,980
TOTAL	**1,373**	**30,818**	**326**	**121**	**194**	**32,832**

[1] 1 metric ton = 2,205 pounds
[2] GHGs from temporary construction activities are amortized over 30 years.

As demonstrated in Tables 4.2-24 and 4.2-25, none of the affected refinery facilities individually exceed the GHG industrial significance threshold of 10,000 MT/yr before or after mitigation. However, the GHG emissions from the project as a whole exceed the GHG threshold both before and after mitigation. Therefore, the proposed project is considered to have adverse significant GHG impacts after mitigation. Because the proposed project is expected to generate construction-related CO2e emissions, and the operational phase of the proposed project is also expected to generate additional GHG emissions, cumulative GHG adverse impacts after mitigation from the proposed project are considered significant.

While there may be additional measures that could eventually be imposed upon sources with potential increases in GHG emissions, CARB is adopting measures pursuant to AB 32 that would require the maximum technically feasible and cost-effective GHG emission reductions from most of the industry categories affected by the proposed project. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time…" For example, CARB has adopted a Low Carbon Fuel Standard for motor vehicle fuels. In October 2010, CARB has also adopted a GHG reduction cap and trade program that will apply to projects that will need to receive permits, including any projects that may occur as a result of amending the NOx RECLAIM program. CARB GHG reduction measures are required to "achieve the maximum technologically feasible and cost-effective greenhouse gas reductions from sources or categories of sources" (Health and Safety Code §38560). CARB has published two scoping plans, as required by Health and Safety Code §38561, that identifies additional measures CARB intends to adopt that will reduce GHG emissions. The scoping plan is required to identify measures that will achieve "the maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020." (Health and Safety Code §38561 (b)).

All CARB GHG measures are required to meet the "maximum feasible and cost-effective" reductions test. This test is equally as stringent as the CEQA definition of "feasible." Given that CARB has been working on this statutory mandate for several years, and has an entire office and staff devoted to GHG rulemaking, it would not be feasible for SCAQMD staff to develop generally applicable GHG reduction measures that go beyond CARB measures. Thus, application of CARB rules will require the maximum feasible GHG reductions for existing sources.

EPA has stated that because there is no national ambient air quality standard for CO2, or any of the other primary GHGs, and EPA does not plan to promulgate any, the "nonattainment" NSR program that applies to criteria pollutants will not apply to GHGs[12]. However, for a NSR program that applies to attainment pollutants, prevention of significant deterioration (PSD) will also apply. PSD applies to any "major stationary source" of pollutants subject to regulation under the federal CAA. Accordingly, because EPA has promulgated its GHG reduction rules for motor vehicles, GHGs is a pollutant that is subject to regulation under the federal Clean Air Act. EPA has issued its interpretation that GHGs become regulated pollutants as of the time the motor vehicle rule becomes effective (i.e., January 2011). SCAQMD staff concluded at the time that it would not be feasible to begin requiring GHG BACT prior to January 2011, because it would be necessary to amend the agency's rules in order to do so.

EPA promulgated its GHG PSD rule requiring several "steps." In Step 1, which began on January 2, 2011, only facilities that would already be subject to Title V or PSD would be subject to GHG requirements under these programs. In addition, a facility modification would only trigger PSD for GHGs if the modification resulted in an increase of 75,000 MT/yr CO2eq. Therefore, SCAQMD began requiring GHG BACT for sources already subject to PSD and having a GHG increase of 75,000 MT/yr or more, effective January 2, 2011. In Step 2, which occurred between ~~began on~~ July 1, 2011 and June 30, 2013, facilities with a potential to emit 100,000 MT/yr CO2eq or more would be subject to Title V and PSD, regardless of whether they would otherwise be subject to these programs as a result of emissions of other pollutants. Therefore, effective July 1, 2011, SCAQMD started requiring GHG BACT for all new and modified facilities having the potential to emit 100,000 MT/yr CO2eq and having an increase of at least 75,000 MT/yr CO2eq. For the third phase, Step 3, of the GHG Tailoring Rule, effective August 13, 2012, EPA retained the GHG permitting thresholds that were established in Steps 1 and 2 of the GHG Tailoring Rule[13]. Recently, the U.S. Supreme Court held that EPA was limited to Step 1.

At the local level, SCAQMD adopted Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, implementing PSD requirements for GHGs. SCAQMD interprets its Rule 1714 to be consistent with the U.S. Supreme Court decision.

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[12] "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Proposed Rule" ("Tailoring Rule Proposal") 74 FR 55292, 55297 (October 27, 2009).

[13] Environmental Protection Agency, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3 and GHG Plantwide Applicability Limits, Final Rule. 77 FR 41051–41075 (July 12, 2012).

Although the definition of federal BACT for PSD sources is somewhat different from the definition of BACT that SCAQMD uses for nonattainment NSR, this definition is still at least as stringent as the CEQA definition of feasible. Pursuant to federal CAA §169(3) (42 U.S.C. §7479(3)), the term "best available control technology" means in pertinent part "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant." Therefore, GHG BACT is at least as stringent as CEQA's definition of feasible mitigation, which similarly allows consideration of economic, technological and environmental factors. Thus, application of BACT will require the maximum feasible reductions of GHGs at new or modified sources, which would otherwise be subject to PSD. Because the potential GHG increases at each affected facility are individually well below EPA's initial thresholds, GHG BACT would not be required for any of the individual facilities making facility modifications to comply with the proposed project.

Further, in light of the uncertainty associated with the effects of the proposed project on individual facilities whose operators have not submitted any applications for permits to construct as a result of the proposed project, the adoption and implementation of feasible mitigation beyond the requirement of using recycled water when available will not feasibly reduce significant air quality and climate change impacts to a less-than-significant level, because it would not be feasible for the SCAQMD to attempt to develop and impose additional GHG mitigation measures for the myriad of source categories that may be affected by the proposed project. Accordingly, the project-level and cumulative impacts identified as significant in this chapter cannot feasibly be mitigated to a less-than-significant level and remain significant and unavoidable.

SUBCHAPTER 4.3

ENERGY

Introduction

Significance Criteria

Potential Energy Impacts and Mitigation Measures

Cumulative Energy Impacts

Cumulative Mitigation Measures

4.3 ENERGY

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in energy impacts. The energy impact analysis in this PEA identifies the net effect on energy resources from implementing the proposed project.

4.3.1 Introduction

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of new or the modification of existing NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx at the affected facilities, which will provide air quality and human health benefits to the public. However, installing new or modifying existing air pollution control equipment is expected to have potentially adverse energy impacts.

The environmental analysis assumes that installation of NOx control technologies for the affected sources will reduce NOx emissions overall, but activities associated with both the installation of new control devices and the modification of existing control devices will create adverse energy impacts both during the period of its construction and through ongoing daily operations. During installation or modification of add-on air pollution control devices, energy impacts may be generated from the need for diesel fuel to operate onsite construction equipment and heavy-duty vehicles and for gasoline to operate offsite vehicles used for worker commuting. After construction activities are completed, increased use of electricity needed to operate the NOx air pollution control devices and diesel fuel needed to operate offsite vehicles used for delivering fresh materials needed for operations (e.g., supplies, chemicals, fresh catalyst, etc.) and hauling away solid waste for disposal or recycling (e.g., spent catalyst). No increased use of natural gas is expected because the NOx air pollution control devices identified in Table 4.0-2 do not utilize natural gas. The analysis of these impacts can be found in Section 4.3.3. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse energy impacts. Refer to Appendix E for the calculations used to estimate adverse energy impacts during construction and operation.

4.3.2 Significance Criteria

Impacts to energy resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

4.3.3 Potential Energy Impacts and Mitigation Measures

Table 4.3-1 summarizes the estimated number of NOx emission control devices per sector and per equipment/source category. The different types of control devices include Selective Catalytic Reduction (SCR), a proprietary Low Temperature Oxidation technology (LoTOx™) with or without a Wet Gas Scrubber (WGS), and catalyst impregnated filters with a Dry Gas Scrubber (UltraCat DGS). In total, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx™ with WGSs, one LoTOx™ without WGS, and three UltraCat DGSs.

Table 4.3-1
Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	2 SCRs 2 LoTOx™ with WGSs* 1 LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	5	5 LoTOx™ with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx™ with WGS or 1 UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	1	2 SCRs or 1 UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	7	13 SCRs and 1 SCR replacement
		TOTAL	**114 to 117 SCRs** **7 to 8 LoTOx™ with WGSs** **1 LoTOx™ without WGS** **0 to 3 UltraCat DGSs**

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

4.3.3.1 Energy Impacts During Construction

Implementation of the proposed project could potentially result in construction activities at 20 NOx RECLAIM facilities, which are complex industrial facilities. The physical changes that are expected focus on the installation of new or the modification of existing control equipment for the following stationary sources of NOx: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. As previously summarized in Table 4.3-1, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx™ with WGSs, one LoTOx™ without WGS, and three UltraCat DGSs.

During installation or modification of add-on air pollution control devices, adverse energy impacts (e.g., increased demand in energy) may occur during construction due to the need for: 1) diesel fuel to operate onsite construction equipment that cannot utilize or access electricity; 2) diesel fuel to operate heavy-duty and medium-duty vehicles for delivering supplies and hauling waste during construction; and, 3) gasoline to operate offsite vehicles used for worker commuting. Tables 4.3-2 and 4.3-3 summarize the how much diesel fuel and gasoline will be need to construct an assortment of NOx control technologies (including the vehicles for deliveries, hauling and construction workers) at the 20 facilities for the refinery and non-refinery sectors, respectively. Table 4.3-4 summarizes the how much diesel fuel and gasoline will be needed to construct all NOx control equipment at all 20 facilities combined.

To determine whether a project would cause a substantial depletion of existing energy resource supplies for diesel fuel and gasoline, the SCAQMD determines significance for increased fuel use by comparing the potential increases in diesel fuel and gasoline to one percent of supply for each fuel type. As shown in Table 4.3-4, the increased use of diesel fuel and gasoline during construction would not exceed the significance threshold of one percent of supply. As such, these projected increased usages of diesel fuel and gasoline would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, these projected increased usages of diesel fuel and gasoline would not create any significant effects on peak and base period demands on the availability of diesel fuel and gasoline.

As part of the installing or modifying existing air pollution control equipment, electricity could be utilized to operate certain construction equipment in lieu of diesel, such as welders, if access to electricity is available. (In fact, utilizing electricity for welders, in lieu of diesel welders is encouraged and required as part of mitigation for air quality construction emissions.) Any additional electricity that may be needed as part of implementing the proposed project is typically supplied by each affected facility's local electrical utility and if applicable, supplemented by the facility's own cogeneration unit.

Table 4.3-2
Construction Fuel Use By Refinery Facility

Refinery ID	Affected Equipment/ Source Category and Potential NOx Control Equipment	Daily Fuel Usage (gal/day)		Project Fuel Usage (gal/project)	
		Diesel	**Gasoline**	**Diesel**	**Gasoline**
1	SRU/TGU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 14 SCRs total (but only 5 overlap)	2,356	697	316,573	145,165
2	Coke Calciner: 1 LoTOx™ with WGS or 1 Ultracat DGS	478	339	72,373	98,508
3	Boilers/Heaters: 2 SCRs	751	144	97,680	18,663
4	FCCU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 2 SCRs	1,229	482	170,053	117,171
5	FCCU: 1 SCR SRU/TGU: 2 LoTOx™ with WGSs SRU/TGU: 1 SCR Gas Turbine: 3 SCRs Boilers/Heaters: 4 SCRs	3,559	1,368	678,207	328,970
6	FCCU: 1 SCR SRU/TGU: 1 LoTOx™ with WGSs Gas Turbine: 1 SCR Boilers/Heaters: 5 SCRs	3,145	1,069	521,810	241,733
7	FCCU: 1 LoTOx™ without WGS Gas Turbine: 1 SCR Boilers/Heaters: 3 SCRs	1,503	287	195,360	37,326
8	SRU/TGU: 1 LoTOx™ with WGS Boilers/Heaters: 3 SCRs	1,605	554	218,893	126,502
9	FCCU: 1 LoTOx™ with WGS Boilers/Heaters: 2 SCRs	1,229	482	170,053	117,171
	TOTAL	**15,855**	**5,422**	**2,441,003**	**1,231,208**

Table 4.3-3
Construction Fuel Use By Non-Refinery Facility

Non-Refinery ID	Affected Equipment/ Source Category and Potential NOx Control Equipment	Daily Fuel Usage (gal/day)		Project Fuel Usage (gal/project)	
		Diesel	Gasoline	Diesel	Gasoline
1	ICEs: 5 SCRs Gas Turbines: 3 SCRs	126	28	23,654	6,963
2	ICEs: 6 SCRs Gas Turbines: 4 SCRs	126	28	23,654	6,963
3	ICEs: 5 SCRs	126	28	23,654	6,963
4	Gas Turbines: 1 SCR	126	28	23,654	6,963
5	Gas Turbines: 2 SCRs	126	28	23,654	6,963
6	Gas Turbines: 1 SCR	126	28	23,654	6,963
7	Gas Turbines: 2 SCRs	126	28	23,654	6,963
8	Glass Melting Furnace: 2 SCRs or 1 Ultracat DGSs	126	28	23,654	6,963
9	Sodium Silicate Furnace: 1 SCR or 1 Ultracat DGSs	126	28	23,654	6,963
10	Metal Heat Treating Furnace: 1 SCR	126	28	23,6654	6,963
11	Gas Turbines: 1 SCR (replacement of existing)	126	28	23,654	6,963
TOTAL		**1,381**	**306**	**260,197**	**76,595**

Table 4.3-4
Total Projected Construction Fuel Use By All 20 Facilities

Sector	Total Projected Construction Fuel Use	
	Diesel	Gasoline
9 Refineries	15,855 gal/day 2,441,003 gal/project	5,422 gal/day 1,231,208 gal/project
11 Non-Refineries	1,381 gal/day 260,197 gal/project	306 gal/day 76,595 gal/project
TOTAL	**17,236 gal/day 2,701,200 gal/project**	**5,728 gal/day 1,307,803 gal/project**
Threshold Fuel Supply[a]	4,347,945 gal/day 1,587,000,000 gal/project	39,687,671 gal/day 14,486,000,000 gal/project
% of Fuel Supply	0.4% per day 0.2 % per project	0.01% per day 0.01% per project
Significant (Yes/No)[b]	**NO**	**NO**

[a] 2012 California Retail Sales by County; California Energy Commission
http://energyalmanac.ca.gov/gasoline/retail_fuel_outlet_survey/retail_diesel_sales_by_county.html
http://energyalmanac.ca.gov/gasoline/retail_fuel_outlet_survey/retail_gasoline_sales_by_county.html

[b] SCAQMD's Energy Threshold for both types of fuel used is 1% of Fuel Supply.

However, because it is unknown whether electricity would be available to operate construction equipment, any electricity consumption that may occur during construction as a substitute for operating some diesel fueled construction equipment cannot be quantified.

Nonetheless, the amount of electricity that may be needed for this purpose is expected to be minimal because most of the construction activities will be supplied with diesel-powered construction equipment and each affected facility should have enough electricity supplies to provide power to the limited number of electric construction equipment that may be utilized under these circumstances.

Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for electricity usage during construction, implementation of the proposed project is expected to have less than significant energy impacts during construction. Further, any temporary usage of electricity during construction would not be expected to result in the need for new or substantially altered power utility systems. In addition, any temporary usage of electricity that may occur would not be expected to create any significant effects on local or regional electricity supplies or on requirements for additional electricity. Lastly, any temporary usage of electricity that may occur would not be expected to create any significant effects on peak and base period demands for electricity.

4.3.3.2 Mitigation of Construction Energy Impacts

Less than significant adverse impacts associated with energy (e.g., diesel fuel, gasoline, and electricity) are expected from the proposed project during construction, so no mitigation measures during construction are required.

4.3.3.3 Remaining Construction Energy Impacts After Mitigation

The energy analysis concluded that potential energy impacts during construction would be less than significant, so no mitigation measures are required. Thus, energy impacts during construction remain less than significant.

4.3.3.4 Energy Impacts During Operation

After the add-on air pollution control devices are installed and operating, adverse energy impacts (e.g., increased demand in energy) may occur during operation due to the need for: 1) electricity to operate the air pollution control devices; and, 2) diesel fuel to operate heavy-duty and medium-duty vehicles for delivering supplies and hauling waste during operation.

Tables 4.3-5 and 4.3-6 summarize the electricity sources and local utility service providers for the 20 affected facilities belonging to the refinery and non-refinery sectors, respectively.

Table 4.3-5
Facility-Specific Sources of Energy for Refinery Sector

Refinery ID	Electricity Source
1	1. Existing onsite cogeneration plant 2. Southern California Edison
2	1. Existing onsite cogeneration plant 2. Southern California Edison
3	1. Existing onsite cogeneration plant 2. Southern California Edison
4	1. Existing onsite cogeneration plant 2. Los Angeles Department of Water and Power
5	1. Existing onsite cogeneration plant 2. Southern California Edison
6	Southern California Edison
7	1. Existing onsite cogeneration plant 2. Los Angeles Department of Water and Power
8	Southern California Edison
9	Los Angeles Department of Water and Power

Table 4.3-6
Facility-Specific Sources of Energy for Non-Refinery Sector

Non-Refinery ID	Electricity Source
1	Existing onsite cogeneration plant
2	Existing onsite cogeneration plant
3	1. Existing onsite cogeneration plant 2. Southern California Edison
4	1. Existing onsite cogeneration plant 2. Southern California Edison
5	1. Existing onsite cogeneration plant 2. Los Angeles Department of Water and Power
6	1. Existing onsite cogeneration plant 2. Southern California Edison
7	1. Existing onsite cogeneration plant 2. Southern California Edison
8	City of Vernon
9	Southern California Edison
10	Southern California Edison
11	1. Existing onsite cogeneration plant 2. Southern California Edison

Energy information as it relates to operational activities was derived as part of the air quality analysis in Subchapter 4.2 and the calculations are shown in Appendix E of this PEA. If the potential NOx controls are installed and operated, Tables 4.3-7 and 4.3-8 summarize the estimated impacts on operational electricity use on a per facility per sector basis, respectively.

Table 4.3-7
Potential Operational Energy Use Per Refinery Facility

Refinery ID	Affected Equipment/ Source Category and Potential NOx Control Equipment	Potential Increased Electricity Demand (kWh/day)	Potential Increased Instantaneous Electricity Demand (MW)
1	SRU/TGU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 5 SCRs	41,307	1.72
2	Coke Calciner: 1 LoTOx™ with WGS or 1 Ultracat DGS	17,711	0.74
3	Boilers/Heaters: 2 SCRs	1,628	0.07
4	FCCU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 2 SCRs	25,162	1.05
5	FCCU: 1 SCR SRU/TGU: 2 LoTOx™ with WGSs SRU/TGU: 1 SCR Gas Turbine: 3 SCRs Boilers/Heaters: 4 SCRs	24,733	1.03
6	FCCU: 1 SCR SRU/TGU: 1 LoTOx™ with WGSs Gas Turbine: 1 SCR Boilers/Heaters: 5 SCRs	21,878	0.91
7	FCCU: 1 LoTOx™ without WGS Gas Turbine: 1 SCR Boilers/Heaters: 3 SCRs	8,168	0.34
8	SRU/TGU: 1 LoTOx™ with WGS Boilers/Heaters: 3 SCRs	14,307	0.60
9	FCCU: 1 LoTOx™ with WGS Boilers/Heaters: 2 SCRs	20,445	0.85
	TOTAL	**168,170**	**7.01**

In addition, as part of operation for three WGSs at Refineries 2, 4 and 9, NaOH caustic soda solution is required and approximately 2.47 tons per day would be needed. NaOH is produced locally by several chemical processing companies and as such, is locally available for transport. Further, it is likely that the existing local caustic manufacturers can handle the proposed increase in caustic for the entire project. To accommodate the estimated increase in caustic demand, the chemical processing companies may need to increase production, which, in turn, will use more electricity. It takes approximately 2,500 kWh to produce one metric ton of NaOH. Thus, the approximate amount of additional electricity that may be needed to produce additional caustic to meet the needs for these three refineries is approximately 13,235 kWh/day, calculated as follows:

<u>Electricity Needed to Manufacture Caustic Soda Solution:</u>

$$\frac{5.84 \text{ tons NaOH}}{\text{Day}} \times \frac{2{,}000 \text{ lbs}}{\text{Ton}} \times \frac{1 \text{ metric ton}}{2{,}205 \text{ lbs}} \times \frac{2{,}500 \text{ kWh}}{1 \text{ metric ton of NaOH produced}} = \mathbf{13{,}235\ kWh/day}$$

The overall electricity needed during operation activities for the refinery sector as summarized in Tables 4.3-7 include the amount of electricity that may be needed to produce additional NaOH.

Table 4.3-8
Potential Operational Energy Use Per Non-Refinery Facility

Non-Refinery ID	**Affected Equipment/ Source Category and Potential NOx Control Equipment**	**Potential Increased Electricity Demand** (kWh/day)	**Potential Increased Instantaneous Electricity Demand** (MW)
1	ICEs: 5 SCRs Gas Turbines: 3 SCRs	14,368	0.60
2	ICEs: 6 SCRs Gas Turbines: 4 SCRs	3,088	0.13
3	ICEs: 5 SCRs	462	0.02
4	Gas Turbines: 1 SCR	608	0.03
5	Gas Turbines: 2 SCRs	1,217	0.05
6	Gas Turbines: 1 SCR	608	0.03
7	Gas Turbines: 2 SCRs	9,370	0.39
8	Glass Melting Furnace: 2 SCRs	2,916	0.12
9	Sodium Silicate Furnace: 1 Tri-Mer	1,248	0.05
10	Metal Heat Treating Furnace: 1 SCR	11,458	0.48
11	Gas Turbines: 1 SCR (replacement of existing)	0	0
	TOTAL	45,344	1.89

To determine whether a project would cause an increased demand for electricity beyond the current capacities of the electric utilities, the SCAQMD determines significance for increased energy by comparing the potential increases in electricity demand to one percent of supply. Table 4.3-9 summarizes the how much electricity will be needed to construct all NOx control equipment at all 20 facilities combined. To determine if the operational energy use is significant, the total for electricity was compared to the threshold electricity supply as shown in Table 4.3-9.

Table 4.3-9
Total Projected Operational Electricity Demand By All 20 Facilities

Sector	Total Projected Electricity Demand	
	Daily (kwh/day)	Instantaneous (MW)
9 Refineries	168,170	7.01
11 Non-Refineries	45,344	1.89
TOTAL	**213,514**	**8.90**
Threshold Fuel Supply[a]	320,000,000 kWh	13,333 MW
% of Supply	0.07%	0.07%
Significant (Yes/No)[b]	**NO**	**NO**

[a] 2013 Electricity Use in GWh (Aggregated, includes self generation and renewables), for Los Angeles, Orange, Riverside and San Bernardino Counties, California Energy Commission .
[b] SCAQMD's Energy Threshold for electricity is 1% of Supply.

As shown in Table 4.3-9, the increased use of electricity during operation would not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD’s energy threshold of one percent of supply for electricity usage, implementation of the proposed project is expected to have less than significant energy impacts during operation. Further, any usage of electricity during operation would not be expected to result in the need for new or substantially altered power utility systems. In addition, any operational increases in electricity usage that may occur would not be expected to create any significant effects on local or regional electricity supplies or on requirements for additional electricity. Lastly, any increased operational usage of electricity that may occur would not be expected to create any significant effects on peak and base period demands for electricity.

During operation of the projected add-on air pollution control devices, adverse energy impacts (e.g., increased demand in energy) may also occur during operation due to the need for diesel fuel to operate heavy-duty and medium-duty vehicles for delivering supplies and hauling waste. For example, for refinery facilities, heavy-duty truck trips would be needed to deliver chemicals such as ammonia, sodium hydroxide, oxygen, lime, soda ash, and fresh catalyst and to haul away solid waste that may be generated and spent catalyst. Similarly, for non-refinery facilities, medium-duty and heavy-duty truck trips would be needed to deliver chemicals such as ammonia, urea, hydrated lime, and fresh catalyst and to haul away solid waste and filter waste that may be generated and spent catalyst.

Tables 4.3-10 and 4.3-11 summarize the how much diesel fuel and gasoline will be needed for support activities (fuel needed for the vehicles for deliveries and waste hauling) associated with the operation of an assortment of NOx control technologies at the 20 facilities for the refinery and non-refinery sectors, respectively.

Table 4.3-10
Operational Diesel Fuel Use By Refinery Facility

Refinery ID	Affected Equipment/ Source Category and Potential NOx Control Equipment	Diesel Fuel Usage From Heavy-Duty Truck Trips	
		Daily (gal/day)	**Annual (gal/yr)**
1	SRU/TGU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 5 SCRs	215	2,761
2	Coke Calciner: 1 LoTOx™ with WGS or 1 Ultracat DGS	126	1,298
3	Boilers/Heaters: 2 SCRs	61	225
4	FCCU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 2 SCRs	215	1,503
5	FCCU: 1 SCR SRU/TGU: 2 LoTOx™ with WGSs SRU/TGU: 1 SCR Gas Turbine: 3 SCRs Boilers/Heaters: 4 SCRs	337	4,438
6	FCCU: 1 SCR SRU/TGU: 1 LoTOx™ with WGSs Gas Turbine: 1 SCR Boilers/Heaters: 5 SCRs	276	3,753
7	FCCU: 1 LoTOx™ without WGS Gas Turbine: 1 SCR Boilers/Heaters: 3 SCRs	133	1,733
8	SRU/TGU: 1 LoTOx™ with WGS Boilers/Heaters: 3 SCRs	153	2,086
9	FCCU: 1 LoTOx™ with WGS Boilers/Heaters: 2 SCRs	153	3,446
	TOTAL	**1,670**	**21,241**

Table 4.3-11
Operational Diesel Fuel Use By Non-Refinery Facility

Non-Refinery ID	Affected Equipment/ Source Category and Potential NOx Control Equipment	Diesel Fuel Usage From Heavy-Duty & Medium DutyTruck Trips	
		Daily (gal/day)	**Annual (gal/yr)**
1	ICEs: 5 SCRs Gas Turbines: 3 SCRs	55	1,099
2	ICEs: 6 SCRs Gas Turbines: 4 SCRs	55	1,099
3	ICEs: 5 SCRs	55	1,099
4	Gas Turbines: 1 SCR	55	1,099
5	Gas Turbines: 2 SCRs	55	1,099
6	Gas Turbines: 1 SCR	55	1,099
7	Gas Turbines: 2 SCRs	55	1,099
8	Glass Melting Furnace: 2 SCRs	55	1,099
9	Sodium Silicate Furnace: 1 Tri-Mer	55	1,099
10	Metal Heat Treating Furnace: 1 SCR	55	1,099
11	Gas Turbines: 1 SCR (replacement of existing)	55	1,099
	TOTAL	**610**	**12,090**

To determine whether a project would cause a substantial depletion of existing energy resource supplies for diesel fuel, the SCAQMD determines significance for increased diesel fuel use by comparing the potential increases in diesel fuel needed to one percent of supply. Table 4.3-12 summarizes the how much diesel fuel will be needed to operate all NOx control equipment at all 20 facilities combined. To determine if the operational energy use is significant, the total for diesel fuel use was compared to the threshold fuel supply as shown in Table 4.3-12.

Table 4.3-12
Total Projected Operational Diesel Fuel Use By All 20 Facilities

Sector	Total Projected Diesel Fuel Use	
	Daily (gal/day)	**Annual (gal/yr)**
9 Refineries	1,670	21,241
11 Non-Refineries	610	12,090
TOTAL	**2,280**	**33,331**
Threshold Fuel Supply[a]	4,347,945	1,587,000,000
% of Fuel Supply	0.05%	0.002%
Significant (Yes/No)[b]	**NO**	**NO**

[a] 2012 California Retail Sales by County; California Energy Commission http://energyalmanac.ca.gov/gasoline/retail_fuel_outlet_survey/retail_diesel_sales_by_county.html

[b] SCAQMD's Energy Threshold for both types of fuel used is 1% of Fuel Supply.

As shown in Table 4.3-12, the increased use of diesel fuel during operation would not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for diesel fuel usage, implementation of the proposed project is expected to have less than significant energy impacts during operation. As such, the projected increased usage of diesel fuel would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, the projected increased usage of diesel fuel would not create any significant effects on peak and base period demands on the availability of diesel fuel.

4.3.3.5 Mitigation of Operational Energy Impacts

Less than significant adverse impacts associated with energy (e.g., increased usage in electricity, diesel fuel, and gasoline) are expected from the proposed project during operation, so no mitigation measures are required.

4.3.3.6 Remaining Operational Energy Impacts After Mitigation

The energy analysis concluded that potential energy impacts during operation would be less than significant, no mitigation measures were required. Thus, energy impacts during operation remain less than significant.

4.3.4 Cumulative Energy Impacts

Because the project-specific energy impacts do not exceed any applicable significance thresholds, they are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, do not generate significant adverse cumulative energy impacts.

4.3.5 Cumulative Mitigation Measures

Because the project-specific energy impacts during construction and operation are not considered to be cumulatively considerable, no cumulative mitigation measures are required.

SUBCHAPTER 4.4

HAZARDS AND HAZARDOUS MATERIALS

Introduction

Significance Criteria

Potential Hazards and Hazardous Materials Impacts and Mitigation Measures

Cumulative Hazards and Hazardous Materials Impacts

Cumulative Mitigation Measures

4.4 HAZARDS AND HAZARDOUS MATERIALS

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in hazards and hazardous materials impacts. The hazards and hazardous materials impact analysis in this PEA identifies the net effect on hazards and hazardous materials from implementing the proposed project.

The potential for hazards exist in the production, use, storage, and transportation of hazardous materials. For the purposes of this PEA, the term "hazardous materials" refers to both hazardous materials and hazardous wastes. In general, hazards can occur due to natural events, such as earthquake, and non-natural events, such as mechanical failure or human error. The risk associated with each affected facility is defined by the probability of an event and the consequence (or hazards) should the event occur.

Hazardous materials may be found at industrial production and processing facilities. Some facilities produce hazardous materials as their end product, while others use such materials as an input to their production process. Hazardous materials are stored at facilities that produce such materials and at facilities where hazardous materials are a part of the production process. Specifically, storage refers to the bulk handling of hazardous materials before and after they are transported to the general geographical area of use. Currently, hazardous materials are transported throughout the district via all modes of transportation including rail, highway, water, air, and pipeline. Hazard concerns are related to the potential for fires, explosions or the release of hazardous materials/substances in the event of an accident or upset conditions.

4.4.1 Introduction

The NOP/IS (see Appendix F) determined that the proposed project has the potential to generate significant adverse hazards and hazardous materials impacts. The hazard and hazardous materials impacts associated with the operation of the proposed project are potentially significant and the impacts are evaluated in this subchapter.

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of new or the modification of existing NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx at the affected facilities, which will provide air quality and human health benefits to the public. However, installing new or modifying existing air pollution control equipment is expected to have potentially adverse hazards and hazardous materials impacts. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse hazards and hazardous materials impacts.

4.4.2 Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

4.4.3 Potential Hazards and Hazardous Materials Impacts and Mitigation Measures

Table 4.4-1 summarizes the estimated number of NOx emission control devices per sector and per equipment/source category. The different types of control devices include Selective Catalytic Reduction (SCR), a proprietary Low Temperature Oxidation technology (LoTOx™) with or without a Wet Gas Scrubber (WGS), and catalyst impregnated filters with a Dry Gas Scrubber (UltraCat DGS). In total, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx™ with WGSs, one LoTOx™ without WGS, and three UltraCat DGSs.

Table 4.4-1
Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	2 SCRs 2 LoTOx™ with WGSs* 1 LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	5	5 LoTOx™ with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx™ with WGS or 1 UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	1	2 SCRs or 1 UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	7	13 SCRs and 1 SCR replacement
		TOTAL	**114 to 117 SCRs** **7 to 8 LoTOx™ with WGSs** **1 LoTOx™ without WGS** **3 UltraCat DGSs**

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

Several components with regard to reducing NOx emissions by installing new or modifying existing NOx controls as part of implementing the proposed project may affect the use, storage and transport of hazards and hazardous materials during operational-related activities. Thus, the routine transport of hazardous materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project.

The key effects of implementing the proposed project and the determination of which aspects involve hazards and hazardous materials focus on: 1) the anticipated increase of substances used to operate the new or modified NOx controls; and, 2) the increased capture of hazardous substances as part of the overall NOx reduction effort. Table 4.4-2 contains a summary of the substances that may be used, stored and transported as part of implementing the proposed project.

Table 4.4-2
Substances Used by NOx Control Technologies

Sector	Equipment/Source Category	Potential NOx Control Devices	Proposed Substances To Be Used/Increased for NOx Control
Refinery	FCCUs	1. SCRs 2. LoTOx™ with WGSs 3. LoTOx™ without WGS	1. NH3 and fresh catalyst 2. NaOH and fresh catalyst 3. Oxygen
Refinery	Refinery Process Heaters and Boilers	SCRs	NH3 and fresh catalyst
Refinery	Refinery Gas Turbines	SCRs	NH3 and fresh catalyst
Refinery	SRU/TGUs	1. LoTOx™ with WGSs 2. SCRs	1. Soda Ash 2. NH3 and fresh catalyst
Refinery	Petroleum Coke Calciner	1. LoTOx™ with WGS 2. UltraCat DGS	1. NaOH and fresh catalyst 2. NH3 and Hydrated Lime – Ca(OH)2
Non-Refinery	Container Glass Melting Furnaces	1. SCR 2. UltraCat DGS	1. NH3 and fresh catalyst 2. Hydrated Lime – Ca(OH)2 and fresh catalyst
Non-Refinery	Sodium Silicate Furnaces	1. SCR 2. UltraCat DGS	1. NH3 and fresh catalyst 2. NH3 and fresh catalyst
Non-Refinery	Metal Heat Treating Furnaces	SCRs	NH3 and fresh catalyst
Non-Refinery	ICEs (Non-Refinery/Non-Power Plant)	SCRs	NH3 and fresh catalyst
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	SCRs	NH3 and fresh catalyst

Hazard Safety Regulations

Notwithstanding implementation of the proposed project, operators of each affected facility must comply or continue to comply with various regulations, including Occupational Safety and Health Administration (OSHA) regulations (29 Code of Federal Regulations (CFR) Part 1910) that require the preparation of a fire prevention plan, and 20 CFR Part 1910 and CCR Title 8 that require prevention programs to protect workers who handle toxic, flammable, reactive, or explosive materials. In addition, §112 (r) of the CAA Amendments of 1990 [42 United States Code (USC) 7401 et. seq.] and Article 2, Chapter 6.95 of the California HSC require facilities that handle listed regulated substances to develop Risk Management Programs (RMPs) to prevent accidental releases of these substances. If any of the affected facilities has already prepared an RMP, it may need to be revised to incorporate any changes that may be associated with the proposed project. The Hazardous Materials Transportation Act is the federal legislation that regulates transportation of hazardous materials.

A number of physical or chemical properties may cause a substance to be hazardous. With respect to determining whether any material identified in Table 4.4-5 is hazardous, each Material Safety Data Sheet (MSDS) has also been consulted for the National Fire Protection Association (NFPA) 704 hazard rating system (i.e. NFPA 704). NFPA 704 is a "standard (that) provides a readily recognized, easily understood system for identifying specific hazards and their severity using spatial, visual, and numerical methods to describe in simple terms the relative hazards of a material. It addresses the health, flammability, instability, and related hazards that may be presented as short-term, acute exposures that are most likely to occur as a result of fire, spill, or similar emergency[1]." In addition, the hazard ratings per NFPA 704 are used by emergency personnel to quickly and easily identify the risks posed by nearby hazardous materials in order to help determine what, if any, specialty equipment should be used, procedures followed, or precautions taken during the first moments of an emergency response. The scale is divided into four color-coded categories, with blue indicating level of health hazard, red indicating the flammability hazard, yellow indicating the chemical reactivity, and white containing special codes for unique hazards such as corrosivity and radioactivity. Each hazard category is rated on a scale from 0 (no hazard; normal substance) to 4 (extreme risk). Table 4.4-3 summarizes what the codes mean for each hazards category.

It is expected that the operators of affected facilities will comply with all applicable design codes and regulations, conform to NFPA standards, and conform to policies and procedures concerning leak detection containment and fire protection. Therefore, no significant adverse offsite hazard impacts are expected as explained in the following sections.

[1] National Fire Protection Association, FAQ for Standard 704. http://www.nfpa.org/faq.asp?categoryID=928&cookie%5Ftest=1#23057

Table 4.4-3

NFPA 704 Hazards Rating Codes

Hazard Rating Code	Health (Blue)	Flammability (Red)	Reactivity (Yellow)	Special (White)
4 = Extreme	Very short exposure could cause death or major residual injury (extreme hazard)	Will rapidly or completely vaporize at normal atmospheric pressure and temperature, or is readily dispersed in air and will burn readily. Flash point below 73°F.	Readily capable of detonation or explosive decomposition at normal temperatures and pressures.	**~~W~~** = Reacts with water in an unusual or dangerous manner.
3 = High	Short exposure could cause serious temporary or moderate residual injury	Liquids and solids that can be ignited under almost all ambient temperature conditions. Flash point between 73°F and 100°F.	Capable of detonation or explosive decomposition but requires a strong initiating source, must be heated under confinement before initiation, reacts explosively with water, or will detonate if severely shocked.	**OXY** = Oxidizer
2 = Moderate	Intense or continued but not chronic exposure could cause temporary incapacitation or possible residual injury.	Must be moderately heated or exposed to relatively high ambient temperature before ignition can occur. Flash point between 100°F and 200°F.	Undergoes violent chemical change at elevated temperatures and pressures, reacts violently with water, or may form explosive mixtures with water.	**SA** = Simple asphyxiant gas (includes nitrogen, helium, neon, argon, krypton and xenon).
1 = Slight	Exposure would cause irritation with only minor residual injury.	Must be heated before ignition can occur. Flash point over 200°F.	Normally stable, but can become unstable at elevated temperatures and pressures	
0 = Insignificant	Poses no health hazard, no precautions necessary	Will not burn	Normally stable, even under fire exposure conditions, and is not reactive with water.	

Hazard Impacts on Water Quality

A spill of any hazardous material that is used and stored at any of the affected facilities could occur under upset conditions such as an earthquake, tank rupture, or tank overflow. Spills could also occur from corrosion of containers, piping and process equipment; and leaks from seals or gaskets at pumps and flanges. A major earthquake would be a potential cause of a large spill. Other causes could include human or mechanical error. Construction of the vessels and foundations in accordance with the Uniform Building Code Zone 4 requirements helps structures to resist major earthquakes without collapse, but may result in some structural and non-structural damage following a major earthquake. Any facility with storage tanks on-site is currently required to have emergency spill containment equipment and would implement spill control measures in the event of an earthquake. Storage tanks typically have secondary containment such as a berm which would be capable of containing 110 percent of the contents of the storage tanks. Therefore, should a rupture occur, the contents of the tank would be collected within the containment system and pumped to an appropriate storage tank.

Spills at the affected facilities would generally be collected within containment areas. Large spills outside of containment areas at the affected facilities are expected to be captured by the process water system where they could be collected and controlled. Spilled material would be collected and pumped to an appropriate tank or sent off-site if the materials cannot be used on-site. Because of the containment system design, spills are not expected to migrate from the spill site and as such, potential adverse water quality hazard impacts are considered to be less than significant.

Project Specific Impacts

The following discussion describes the hazards profile for each substance involved with proposed NOx control equipment.

Caustic

For any operator that chooses to install a WGS for a FCCU, hazardous materials may be needed to operate the WGSs depending on the source category and additional solid waste is expected to be generated. Caustic is a key ingredient needed for the operation of a WGS. While there are several types of caustic solutions that can be used in WGS operations, caustic made from sodium hydroxide (NaOH) is the most commonly used for WGSs for FCCUs and it is considered an acutely hazardous substance. Located on the MSDS for NaOH (50 percent by weight), the hazards ratings are as follows: health is rated 3 (highly hazardous), flammability is rated 0 (none) and reactivity is rated 1 (slightly hazardous).

For WGSs that may be installed to control NOx from SRU/TGUs, the caustic used in the WGS is made from soda ash, instead of NaOH. Soda ash is the common name for sodium carbonate (Na2CO3), a non-toxic, non-cancerous, and non-hazardous substance. Located on the MSDS for Na2CO3, the hazards ratings are as follows: health is rated 2 (moderate), flammability is rated 0 (none) and reactivity is rated 0 (none). Soda ash has a NFPA health rating 2 because it corrosive and may be harmful if inhaled and may cause skin irritation and workers handling soda ash will need to take the necessary precautions when dealing with this substance. Thus, less than significant increases in hazards associated with the use, storage, or transportation relative to the deliveries of soda ash is expected.

As previously analyzed in Subchapter 4.2 in the air quality discussion, for "worst-case" operations, 5.84 tons per day of NaOH (50 percent solution, by weight) is estimated to be needed to operate three WGSs at three refineries. In addition, even though the refineries may already use NaOH elsewhere in their facilities, for the purpose of conducting a "worst-case" construction analysis, one 10,000 gallon storage tank for caustic solution was assumed to be constructed for every WGS installed.

As previously summarized in Table 4.2-22 in Subchapter 4.2, for each refinery that was projected to increase the use in the acutely hazardous substance NaOH, the filling loss and the working loss of each NaOH tank was calculated, added together, and that sum was compared to the most stringent Rule 1401 Screening Emission Level for NaOH (0.004 pounds per hour at the nearest receptor distance of 25 meters). None of the total hourly loss projections exceeded the acute screening level for NaOH for any of the affected facilities. Because the screening level for NaOH was not exceeded for any of the affected facilities, no significant hazards and hazardous materials impacts with respect to NaOH uses are expected from the proposed project. NaOH is not classified as a carcinogen, so a cancer risk analysis was not performed.

It is expected that the affected facilities will receive NaOH from a local supplier located in the greater Los Angeles area. Deliveries of NaOH (50 percent by weight) would be made by tanker truck via public roads. The maximum capacity of a NaOH tanker truck is approximately 6,000 gallons.

The projected consumption and the annual deliveries of NaOH are summarized in Tables 4.4-4. To accommodate the increased demand in NaOH, there will be an increase in truck deliveries to supply NaOH to the facilities that need it. Table 4.4-4 also summarizes the annual and peak daily truck deliveries needed to supply NaOH. Based on the volume of NaOH solution (50 percent by weight) needed, the calculations assume that one 10,000 gallon capacity storage tank will be installed at each affected facility for NaOH storage. The amount of annual deliveries is based on the assumption that one delivery truck can hold 6,000 gallons per truck load. While the number of annual NaOH deliveries will vary based on each facility's needs, the peak daily truck deliveries would be one truck per day per facility. Based on the annual deliveries estimates, each facility is not expected to exceed the peak of one delivery per day per facility. However, the "worst-case" assumption for a peak daily delivery frequency from a supplier would be to deliver 10,000 gallons of NaOH to two facilities to fill two new NaOH tanks on the same day. Regulations for the transport of hazardous materials by public highway are described in 49 CFR §§ 173 and 177.

Table 4.4-4
Summary of NaOH Deliveries

Refinery ID	Daily Increase in NaOH Demand (tons/day)	Annual Increase in NaOH Demand (tons/year)	Peak Daily NaOH Deliveries (truck trips/day)	Annual NaOH Deliveries [1] (truck trips/year)
2	3.37	1,228	1	32
4	0.45	164	1	5
9	2.02	737	1	19
Total	**5.84**	**2,129**	**3**	**56**

[1] Annual NaOH deliveries are calculated based on one delivery truck holding 6,000 gallons per truck load. For example, for Refinery 4: 164 tons/yr NaOH x 2,000 lbs/ ton = 328,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 25,685 gal/year x 1 truck/6,000 gallons = 4.28 trucks/year (rounded up to 5 to be conservative).

Both the refineries currently receive NaOH from local suppliers located in the greater Los Angeles area. As is currently the case with existing NaOH deliveries, deliveries of additional NaOH would be made to each facility by tanker truck via public roads. NaOH is typically delivered in 6,000 gallon trucks, so the proposed project would not introduce any new transportation hazards for NaOH.

The onsite storage and handling of NaOH creates the possibility of an accidental spill and release of NaOH. However, because NaOH has such a low vapor pressure (6.33 mm Hg at 40 ^{o}C or 104 ^{o}F) when compared to water (55.3 mm Hg at 40 ^{o}C or 104 ^{o}F) at the same temperature, any spill of NaOH would not be expected to evaporate faster than water. Thus, any spill of NaOH would be expected to stay in liquid form and would not likely exceed the ERPG-2 vapor concentration of five milligrams per cubic meter for NaOH. Further, operators at each affected facility who construct a new NaOH storage tank will need to build a containment berm large enough to hold 110 percent of the tank capacity in the event of an accidental release due to tank rupture. Thus, any spill of NaOH would not be expected to migrate beyond the boundaries of the berm on-site. Thus, any spill of NaOH is not expected to present a potential offsite public and sensitive receptor exposure. Lastly, since NaOH is not a flammable compound, other types of heat-related hazard impacts such as fires, explosions, boiling liquid – expanding vapor explosion (BLEVE) are not expected to occur and, therefore, will not be evaluated as part of this hazards analysis.

In conclusion, the hazards and hazardous materials impacts due to the use, tank rupture and the accidental release of NaOH will be less than significant for the proposed project.

Hydrated Lime

For any operation that chooses to install an Ultracat DGSs, a dry calcium- and sodium-based alkaline powdered sorbent can be used to absorb NOx from the flue (outlet) gas stream. The sorbent expected to be used in the Ultracat DGSs for the coke calciner and the container glass melting furnaces will be hydrated lime, also known as calcium hydroxide (Ca(OH)2). Approximately 2.7 tons per day of hydrated lime may be needed as part of operating two UltraCat DGSs at two facilities (one refinery and one non-refinery facilities). Note that the third UltraCat DGS is assumed to only use ammonia because an evaluation of the sodium silicate furnaces exhaust shows that the use of hydrated lime would not be effective for reducing NOx emissions.

Calcium carbonate is a non-toxic, non-cancerous, and non-hazardous substance. The NFPA has not assigned a rating for calcium carbonate. The solid waste by-products that may be generated from this process would also not be considered hazardous waste. Because calcium carbonate is not considered to be hazardous, no increase in transportation hazards relative to the deliveries of calcium carbonate or the hauling of calcium carbonate waste is expected. In conclusion, the hazards and hazardous materials impacts due to the use of hydrated lime and the recycling or disposal of its solid, non-hazardous waste by-product is expected to be less than significant for the proposed project.

Ammonia

Ammonia (NH3,) though not a carcinogen, is a chronic and acutely hazardous material. Located on the MSDS for NH3 (19 percent by weight), the hazards ratings are as follows: health is rated 3 (highly hazardous), flammability is rated 1 (slight) and reactivity is rated 0 (none). Therefore, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents) and onsite or offsite spills for each of the facilities that currently use or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment. A toxic gas cloud is the release of a volatile chemical such as anhydrous ammonia that could form a cloud and migrate off-site, thus exposing individuals. Anhydrous ammonia is heavier than air such that when released into the atmosphere, would form a cloud at ground level rather than be dispersed "Worst-case" conditions tend to arise when very low wind speeds coincide with the accidental release, which can allow the chemicals to accumulate rather than disperse.

Though there are facilities that may be affected by the proposed project and that are currently permitted to use anhydrous ammonia, for new construction, however, current SCAQMD policy no longer allows the use of anhydrous ammonia. To minimize the hazards associated with using ammonia for air pollution control technology, it is the permitting policy of the SCAQMD to require the use of 19 percent by volume aqueous ammonia in air pollution control equipment for the following reasons: 1) 19 percent aqueous ammonia does not travel as a dense gas like anhydrous ammonia; and 2) 19 percent aqueous ammonia is not on any acutely hazardous material lists unlike anhydrous ammonia or aqueous ammonia at higher percentages. As such, SCAQMD staff does not issue permits for the use of anhydrous ammonia or aqueous ammonia in concentrations higher than 19 percent by volume for use in SCR systems. As a result, this analysis focuses on the use of 19 percent by volume aqueous ammonia. Thus, because aqueous ammonia (at 19 percent by weight) would be required for any permits issued for the installation of air pollution control equipment that utilize ammonia, no new hazards from toxic clouds are expected to be associated with the proposed project.

In addition, the shipping, handling, storage, and disposal of hazardous materials inherently poses a certain risk of a release to the environment. Thus, the routine transport of hazardous materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project. Further, if the control option chosen by each affected facility is to install control technology that utilizes ammonia, such as SCR or a DGS, the proposed project may alter the transportation modes for feedstock and products to/from the existing facilities such as aqueous ammonia and catalyst.

The analysis of hazard impacts can rely on information from past similar projects (i.e., installing new, or retrofitting existing equipment with NOx control technology that utilizes ammonia to comply with SCAQMD rules and regulations and installation of associated ammonia storage tanks) where the SCAQMD was the lead agency responsible for preparing an environmental analysis pursuant to CEQA. To the extent that future projects to install NOx control technology that utilizes ammonia and associated ammonia storage equipment conform to the ammonia hazard analysis in this PEA, no further hazard analysis may be necessary. If site-specific characteristics are involved with future projects to install NOx control equipment that utilize ammonia that are outside the scope of this analysis, a further ammonia hazards analysis may be warranted.

The maximum capacity of an ammonia tanker truck is approximately 7,000 gallons. Based on, the "worst-case" assumption for delivery frequency from a supplier would be to deliver

If all 117 SCRs are installed at all 20 facilities and one Ultracat DGS is installed at one facility, approximately 39.5 tons per day (equivalent to approximately 10,284 gallons per day) of aqueous ammonia (at 19 percent concentration) would be needed to operate the equipment. It is expected that the affected facilities will receive ammonia from a local ammonia supplier located in the greater Los Angeles area. Deliveries of aqueous ammonia would be made by tanker truck via public roads. Since one ammonia delivery truck can deliver up to 7,000 gallons per visit, based on the peak daily total volume of ammonia that would be needed, two trucks would be needed on a peak day. However, because the deliveries are spread across 20 facilities, the analysis conservatively assumes that 28 tankers carrying up to 7,000 gallons per truck would visit all 20 facilities on a peak day. Because the size of the aqueous ammonia storage tanks varies from 600 gallons to 11,000 gallons and the amount needed on a daily basis per facility will also vary, the actual amount of aqueous ammonia delivered per facility on a peak day will vary. The onsite storage capacity and the projections for future ammonia use and storage are estimated in Appendix E.

The accidental release of ammonia from a delivery and use is a localized event (i.e., the release of ammonia would only affect the receptors that are within the zone of the toxic endpoint). The accidental release from a delivery would also be temporally limited in the fact that deliveries are not likely to be made at the same time in the same area. Based on these limitations, it is assumed that an accidental release would be limited to a single delivery or single facility at a time. In addition, it is unlikely that an accidental release from both a delivery truck and the stationary storage tank would result in more than the amount evaluated in the catastrophic release of the storage tank because the level of ammonia in the storage tanks would be low or else the delivery trip would not be necessary.

Ammonia Transportation Release Scenario:
To analyze the effects of aqueous ammonia as a result of an accidental release due to tank rupture, a Consequence Analysis using the EPA RMP*Comp (Version 1.07) is typically performed. Aqueous ammonia trucks have a capacity of 7,000 gallons. EPA's RMP*Comp was used to estimate the zone of impact from a worst-case release. Although it is SCAQMD policy to reduce potential hazards associated with ammonia by requiring a permit condition that limits the aqueous ammonia concentration to 19 percent, the EPA model only has the capability of evaluating the hazard potential of 20 percent aqueous ammonia. Therefore, the potential adverse impacts from aqueous ammonia were evaluated based on 20 percent aqueous ammonia. Based on the worst-case defaults, the toxic endpoint from a delivery truck would be 0.4 miles.

A hazard analysis is dependent on knowing the exact location of the spill (e.g., meteorological conditions, location of the receptor, et cetera, a site-specific hazard analysis is difficult to conduct without this information. Since SCAQMD staff does not currently know the exact location of ammonia storage tanks that would be installed in the future, to estimate a worst-case analysis, the RMP*COMP worst-case assumptions were used:

Location of tank~~s~~: Stand alone tanks (i.e., not within a building)

Quantity Released: 7,000 gallons of aqueous ammonia

Liquid Temperature at the time of the spill: 77 degrees Fahrenheit

Mitigation Measures: None

Topography: Urban surroundings with many obstacles in the immediate area

Toxic Endpoint: 0.14 milligrams per liter (basis: ERPG-2)

Wind Speed: 1.5 meters per second (3.4 miles per hour)

Air Temperature: 77 degrees Fahrenheit

The estimated distance to the toxic endpoint from a worst-case delivery truck release is 0.4 miles or 2,112 feet. Since sensitive receptors are expected to be found within 0.4 miles from roadways, the hazards and hazardous materials impacts due to-a delivery truck accident will be potentially significant. Therefore, the proposed project has the potential to generate significant adverse hazard impacts during transportation as a result of the potential for accidental releases of delivered aqueous ammonia.

Ammonia Tank Rupture Scenario 1 (Non-Refinery Sector):
Based on engineering estimates and discussion with control technology vendors, it was estimated that the largest aqueous ammonia tank that would be installed at a non-refinery facility would be 5,000 gallons. All ammonia tanks are required to be installed within berms that hold 110 percent of the contents of the tank. EPA's RMP*Comp was used to estimate the zone of impact from a worst-case release. Although it is SCAQMD policy to reduce potential hazards associated with ammonia by requiring a permit condition that limits the aqueous ammonia concentration to 19 percent, the EPA model only has the capability of evaluating the hazard potential of 20 percent aqueous ammonia. Therefore, the potential adverse impacts from aqueous ammonia were evaluated based on the 20 percent aqueous ammonia. Further, since it is assumed that an aqueous ammonia tank servicing one or more SCR systems would need to be relatively near to the existing equipment, the toxic endpoint for aqueous ammonia from a worst-case failure of a storage tank would significantly adversely affect the sensitive receptors within 0.1 mile of the existing equipment.

A hazard analysis is dependent on knowing the exact location of the hazard within the site (e.g., location of the ammonia storage tank(s)), meteorological conditions, location of the receptor, et cetera, a site-specific hazard analysis is difficult to conduct without this information. Since SCAQMD staff does not currently know the exact location of ammonia storage tanks that would be installed in the future, to estimate a worst-case analysis, the RMP*COMP worst-case assumptions were used:

Location of tanks: Stand alone tanks not within a building

Quantity Released: 5,500 gallons of aqueous ammonia will be spilled into a berm (the total of one 5,000 gallon tanks plus 10 percent to account for a rupture during filling)

Liquid Temperature at the time of the spill: 77 degrees Fahrenheit

Mitigation Measures: Release into an open berm, in direct contact with outside air

Topography: Urban surroundings with many obstacles in the immediate area

Toxic Endpoint: 0.14 milligrams per liter (basis: ERPG-2)

Wind Speed: 1.5 meters per second (3.4 miles per hour)

Air Temperature: 77 degrees Fahrenheit

The estimated distance to the toxic endpoint from the facility is 0.1 miles or 528 feet. There are no schools or other sensitive receptors located within 0.1 miles of any of the non-refinery facilities. Thus, the hazards and hazardous materials impacts due to tank rupture for non-refinery facilities will be less than significant. Therefore, the proposed project does not have the potential to generate significant adverse hazard impacts as a result of the potential for accidental releases of aqueous ammonia.

Ammonia Tank Rupture Scenario 2 (Refinery Sector):
Based on engineering estimates and discussion with control technology vendors, it was estimated that the largest aqueous ammonia tank that would be installed at a refinery facility would be 11,000 gallons. Although it is SCAQMD policy to reduce potential hazards associated with ammonia by requiring a permit condition that limits the aqueous ammonia concentration to 19 percent, the EPA model only has the capability of evaluating the hazard potential of 20 percent aqueous ammonia. Therefore, the potential adverse impacts from aqueous ammonia were evaluated based on the 20 percent aqueous ammonia. Further, since it is assumed that an aqueous ammonia tank servicing one or more SCR systems would need to be relatively near to the existing equipment, the toxic endpoint for aqueous ammonia from a worst-case failure of a storage tank would significantly adversely affect the sensitive receptors within 0.1 mile of the existing equipment.

A hazard analysis is dependent on knowing the exact location of the hazard within the site (e.g., location of the ammonia storage tank(s)), meteorological conditions, location of the receptor, et cetera, a site-specific hazard analysis is difficult to conduct without this information. Since SCAQMD staff does not currently know the exact location of ammonia storage tanks that would be installed in the future, to estimate a worst-case analysis, the RMP*COMP worst-case assumptions were used:

Location of tanks: Stand alone tanks not within a building

Quantity Released: 12,100 gallons of aqueous ammonia will be spilled into a berm (the total of one 11,000 gallon tanks plus 10 percent to account for a rupture during filling)

Release Rate: 11.7 pounds per minute

Liquid Temperature at the time of the spill: 77 degrees Fahrenheit

Mitigation Measures: Release into an open berm, in direct contact with outside air

Topography: Urban surroundings with many obstacles in the immediate area

Toxic Endpoint: 0.14 milligrams per liter (basis: ERPG-2)

Wind Speed: 1.5 meters per second (3.4 miles per hour)

Air Temperature: 77 degrees Fahrenheit

The estimated distance to the toxic endpoint from any refinery facility is 0.1 miles or 528 feet. Since there are no sensitive receptors within 0.1 miles from any refinery facility, the hazards and hazardous materials impacts due to tank rupture will not be potentially significant. Therefore, for the affected refinery facilities, the proposed project does not have the potential to generate significant adverse hazard impacts as a result of the potential for accidental releases of aqueous ammonia for refinery facilities.

<u>Oxygen</u>

One facility (Refinery 7) is assumed to need an ozone generator which requires a regular supply of oxygen to operate a LoTOx™ unit that may be installed to work with an existing WGS that services the FCCU. Approximately 7,950 pounds of oxygen will be needed on peak day. The analysis assumes that one oxygen delivery truck on a peak day and 44 oxygen delivery trucks in one year will be needed.

Oxygen is an odorless, colorless, nonflammable gas that is stored in tanks or cylinders at high pressure. Oxygen is a non-toxic, non-cancerous, and non-hazardous substance. While no NFPA ratings have been assigned for health, flammability, or reactivity, the NFPA has assigned a special rating to oxygen, OXY, because it is considered an oxidizer that vigorously accelerates combustion. For example, some materials which are noncombustible in air will burn in the presence of an oxygen enriched atmosphere (greater than 23%). In addition, fire resistant clothing may burn and offer no protection in oxygen rich atmospheres. Oxygen may form explosive compounds when exposed to combustible materials or oil, grease, and other hydrocarbon materials. Pressure in a container can build up due to heat and it may rupture if pressure relief devices should fail to function. Upon exposure to intense heat or flame cylinder will vent rapidly and/or rupture violently. Most storage tanks and cylinders are designed to vent contents when exposed to elevated temperatures. Thus, because oxygen is not considered to be hazardous, no increase in hazards associated with the use, storage, or transportation relative to the deliveries of oxygen is expected.

<u>Solid Waste</u>

If the proposed project is implemented, additional solid waste may be generated, depending on the type of NOx control equipment employed. Tables 4.4-5 and 4.4-6 summarize the potential increased amount of solid waste expected to be generated for the refinery and non-refinery sector.

Table 4.4-5

Potential Increase in Solid Waste at Refinery Facilities

Refinery ID	**Proposed Increase in Amount of Solids Collected Due to New NOx Controls** (tons/day)	**Is the proposed increase in Solid Waste Hazardous?**	**Solid Waste will be trucked to:**
1	0.68	NO	Cement Plant for Recycling
2	0.44	NO	Cement Plant for Recycling
3	0	NO	Not Applicable
4	0.44	NO	Cement Plant for Recycling
5	1.75	NO	Cement Plant for Recycling
6	0.88	NO	Cement Plant for Recycling
7	0	NO	Not Applicable
8	0.33	NO	Cement Plant for Recycling
9	1.89	NO	Cement Plant for Recycling
Total	**6.41**		

Table 4.4-6

Potential Increase in Solid Waste at Non-Refinery Facilities

Non-Refinery ID	**Proposed Increase in Amount of Solids Collected Due to New NOx Controls** (tons/day)	**Is the proposed increase in Solid Waste Hazardous?**	**Solid Waste will be trucked to:**
1	0	NO	Not Applicable
2	0	NO	Not Applicable
3	0	NO	Not Applicable
4	0	NO	Not Applicable
5	0	NO	Not Applicable
6	0	NO	Not Applicable
7	0	NO	Not Applicable
8*	1.2	NO	Cement Plant for Recycling or Class III Landfill
9	0	NO	Not Applicable
10	0	NO	Not Applicable
11	0	NO	Not Applicable
Total	**1.2**		

* Solid waste would only be generated if the operator of non-refinery Facility 8 chooses to install an Ultracat system. However, if the operator of non-refinery Facility 8 chooses to install SCR technology, in lieu of the Ultracat system, then no solid waste would be generated.

Thus, because the solid waste that may be generated from the proposed project is not considered to be hazardous, less than significant hazards and hazardous waste impacts associated with the use, storage, or transportation relative to the hauling of solid waste are expected.

Fresh and Spent Catalyst

Commercial catalysts used in SCRs are comprised of a base material of titanium dioxide (TiO2) that is coated with either tungsten trioxide (WO3), molybdic anhydride (MoO3), vanadium pentoxide (V2O5), or iron oxide (Fe2O3). SCR catalysts are replaced approximately one every five years. The key hazards associated with the proposed project are the crushing of the spent catalyst and transporting it for disposal or recycling. Recycling of catalyst means hauling the spent catalyst to a cement plant located outside of the District for use in manufacturing cement.

With respect to hazards and hazardous materials, there will be an increase in the frequency of truck transportation trips to remove the spent catalyst as hazardous materials or hazardous waste from each affected facility. However, facilities that have existing catalyst-based operations currently recycle the catalysts blocks, in lieu of disposal. Moreover, due to the heavy metal content and relatively high cost of catalysts, recycling can be more lucrative than disposal. Thus, facilities that have existing SCR units and choose to employ additional SCR equipment, in most cases already recycle the spent catalyst and subsequently may continue to do so with any additional catalyst that may be needed..

Although recycling may be the more popular (and potentially lucrative) consideration, it is possible that facilities may choose to dispose of the spent catalyst in a landfill. The composition and type of the catalyst will determine the type of landfill that would be eligible to handle the disposal. For example, catalysts with a metal structure would be considered a metal waste, like copper pipes, and not a hazardous waste. Therefore, metal structure catalysts would not be a regulated waste requiring disposal in a Class I landfill, unless it is friable or brittle. As ceramic-based catalysts contain a fiber-binding material, they are not considered friable or brittle and, thus, would not be a regulated waste requiring disposal in a Class I landfill. Furthermore, typical catalyst materials are not considered to be water soluble, which also means they would not require disposal in a Class I landfill. In both cases, spent catalyst would not require disposal in a Class I landfill.

A number of physical or chemical properties may cause a substance to be hazardous, including toxicity (health), flammability, reactivity, and any other specific hazard such as corrosivity or radioactivity. Based on a hazard rating from 0 to 4 (0 = no hazard; 4 = extreme hazard) located on the Material Safety Data Sheet (MSDS) the hazard rating for silica/alumina catalyst, for example, health is rated 1 (slightly hazardous), flammability is rated 0 (none) and reactivity is rated 0 (none). However, if nickel is deposited on the catalyst, the hazard rating is 2 for health (moderately toxic), 4 (extreme fire hazard) for flammability, 1 for reactivity (slightly hazardous if heated or exposed to water). The particular composition of the catalyst used in the SCR units, combined with the metals content of the flue gas will determine the hazard rating and whether the spent catalyst is considered a hazardous material or hazardous waste. This distinction is important because a spent catalyst that qualifies as a hazardous material could be still be recycled (e.g., to be reused by another industry such as manufacturing Portland cement). However, for any spent catalyst that is considered hazardous waste, if it is not recycled, then it must be disposed of in a landfill that can accept hazardous waste.

Based on the aforementioned information, it is likely that spent catalysts would be considered a "designated waste," which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (California Code of Regulations, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts would likely be disposed of in a Class II landfill or a Class III landfill that is fitted with liners. Based on the remaining permitted Class III landfill capacity data for each county as provided in Subchapter 3.6 – Solid and Hazardous Waste, Table 3.6-2, the total remaining permitted Class III landfill capacity in Los Angeles, Orange, Riverside, and San Bernardino counties is 107,933 tons per day.

Proximity to Schools

Of the facilities that may install NOx control equipment, none of the facilities in either the refinery sector or non-refinery sector are located within one-quarter mile of an existing or proposed school. Therefore, no potential for adversely significant impacts from hazardous emissions onsite or the handling of acutely hazardous materials, substances and wastes on sensitive receptors is expected from the proposed project.

Summary

Table 4.4-7 summarizes the substances that may be involved in the various processes at the affected facilities.

Table 4.4-7
Substances that May Be Affected By The Proposed Project

Substance	Potential Overall Increase, Decrease, or No Change from Existing Setting?	Contains TAC(s) per SCAQMD Rule 1401?	Hazardous per CalARP?	NFPA Rating: Health (Blue)	NFPA Rating: Flammability (Red)	NFPA Rating: Reactivity (Yellow)	NFPA Rating: Special (White)
Hydrated Lime - Ca(OH)2	Increase	No	No	N/A	N/A	N/A	N/A
NaOH Caustic (50% by weight)	Increase	Yes, Acute (non-cancer)	Yes	3	0	1	None
Soda Ash Caustic (sodium carbonate)	Increase	No	No	2	0	0	None
NH3 (19% by weight)	Increase	Yes, Chronic & Acute (non-cancer)	Yes	3	1	0	None
Oxygen	Increase	No	No	0	0	0	Oxy
Solid Waste	Increase	No	No	N/A	N/A	N/A	N/A
Fresh Catalyst	Increase	No	No	N/A	N/A	N/A	N/A
Spent Catalyst	Increase	No	No	N/A	N/A	N/A	N/A

NFPA Hazard Code Key: 4 = Extreme; 3 = High; 2 = Moderate; 1 = Slight; 0 = Insignificant; N/A = NFPA hazard is not assigned.

Some of the substances listed are considered hazardous while others are not. Of the substances listed in this table, the only net increase in the use of a hazardous material will be for NaOH and ammonia. The effects of the potential increased use of NaOH and ammonia have been previously analyzed in the "Caustic" and "Ammonia" discussions, respectively. For the remaining substances identified, there will be no change in hazards from the existing setting. Thus, none of the changes to the existing setting is expected to result in a significant adverse impact for hazards and hazardous materials.

Project-Specific Impacts – Conclusion

Based on the preceding description of hazards and hazardous materials impacts, the proposed project is expected to generate significant adverse hazards and hazardous materials impacts for ammonia deliveries and less than significant hazards and hazardous materials impacts for ammonia use and storage. For the substances other than ammonia listed in Table 4.4-8, the proposed project is expected to generate less than significant hazards and hazardous materials impacts. To the extent that future projects to install new or modify existing NOx controls conform with the hazard analysis in this PEA, no further hazard analysis may be necessary. However, if site-specific characteristics are involved with future projects that are outside the scope of this analysis, further hazards analysis may be warranted.

Project-Specific Mitigation: The analysis concluded that the hazards and hazardous materials impacts from implementing the proposed project are considered to be adverse for ammonia deliveries. Therefore, mitigation measures are required. However, no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia.

The analysis also concluded that the hazards and hazardous materials impacts from implementing the proposed project are considered to be less than significant for ammonia use and storage. Finally, for the substances other than ammonia listed in Table 4.4-8, analysis concluded that the proposed project is expected to generate less than significant hazards and hazardous materials impacts. Therefore, mitigation measures are not required.

Remaining Impacts After Mitigation: The hazards and hazardous materials analysis concluded that potential hazards and hazardous materials impacts for ammonia deliveries would be significant such that mitigation measures are required. However, because there are no feasible mitigation measures, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia, to reduce ammonia transportation impacts to less than significant, the hazards and hazardous materials impacts for the ammonia deliveries remain significant.

For ammonia use and storage and for the other substances listed in Table 4.4-8, the hazards and hazardous materials analysis concluded that potential hazards and hazardous materials impacts would be less than significant, such that no mitigation measures are required. Thus, the hazards and hazardous materials impacts for these substances remain less than significant.

4.4.4 Cumulative Hazards and Hazardous Materials Impacts

Because the project-specific hazards and hazardous materials impacts for ammonia deliveries would potentially create significant impacts, they are considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, generate significant adverse cumulative hazards and hazardous materials impacts.

For ammonia use and storage and for the other substances listed in Table 4.4-8, the project-specific hazards and hazardous materials impacts do not exceed any applicable significance thresholds; thus, they are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, do not generate significant adverse cumulative hazards and hazardous materials impacts.

4.4.5 Cumulative Mitigation Measures

Because the project-specific hazards and hazardous materials impacts are considered to be cumulatively considerable for ammonia deliveries, cumulative mitigation measures for hazards and hazardous materials impacts for ammonia deliveries are required. However, since no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia, no feasible cumulative mitigation measures for ammonia deliveries have been identified.

For ammonia use and storage and for the other substances listed in Table 4.4-8, because the project-specific hazards and hazardous materials impacts are not considered to be cumulatively considerable, no cumulative mitigation measures for hazards and hazardous materials impacts for ammonia use and storage and for the other substances listed in Table 4.4-8 are required.

SUBCHAPTER 4.5

HYDROLOGY AND WATER QUALITY

Introduction

Significance Criteria

Potential Hydrology and Water Quality Impacts and Mitigation Measures

Cumulative Hydrology and Water Quality Impacts

Cumulative Mitigation Measures

4.5 HYDROLOGY AND WATER QUALITY

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in adverse hydrology and water quality impacts. The hydrology and water quality analysis in this PEA identifies the net effect of hydrology and water quality from implementing the proposed project.

4.5.1 Introduction

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. The different types of control devices include SCR, LoTOx^{TM} with or without a WGS, and catalyst impregnated filters with an UltraCat DGS. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx at the affected facilities, which will provide air quality and human health benefits to the public. However, installing new or modifying existing air pollution control equipment is expected to have potentially adverse hydrology and water quality impacts. The analysis of these impacts can be found in Section 4.5.3. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse hydrology and water quality impacts. Refer to Appendix E for the calculations used to estimate adverse hydrology and water quality impacts during construction and operation.

4.5.2 Significance Criteria

Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Demand:

- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.
- The project increases demand for total water by more than five million gallons per day.

Water Quality:

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.

- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

4.5.3 Potential Hydrology and Water Quality Impacts and Mitigation Measures

Table 4.5-1 summarizes the estimated number of NOx emission control devices per sector and per equipment/source category. The different types of control devices include Selective Catalytic Reduction (SCR), a proprietary Low Temperature Oxidation technology (LoTOx^{TM}) with or without a Wet Gas Scrubber (WGS), and catalyst impregnated filters with a Dry Gas Scrubber (UltraCat DGS).). In total, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx^{TM} with WGSs, one LoTOx^{TM} without WGS, and three UltraCat DGSs.

Table 4.5-1
Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	2 SCRs 2 LoTOx^{TM} with WGSs* 1 LoTOx^{TM} without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	5	5 LoTOx^{TM} with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx^{TM} with WGS or 1 UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	1	2 SCRs or 1 UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	7	13 SCRs and 1 SCR replacement
		TOTAL	**114 to 117 SCRs** **7 to 8 LoTOx^{TM} with WGSs** **1 LoTOx^{TM} without WGS** **3 UltraCat DGSs**

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

4.5.3.1 Hydrology and Water Quality Impacts During Construction

Implementation of the proposed project could potentially result in construction activities at 20 NOx RECLAIM facilities, which are complex, well-established and mostly paved, industrial facilities. The physical changes that are expected from implementing the proposed project focus on the installation of new or the modification of existing control equipment for the following stationary sources of NOx: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. As previously summarized in Table 4.3-1, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx^{TM} with WGSs, one LoTOx^{TM} without WGS, and three UltraCat DGSs.

During installation or modification of add-on air pollution control devices, adverse hydrology and water quality impacts may occur during construction due to the need for water for dust suppression. Depending on the proposed location within each facility's boundaries for the siting of any new control equipment that may be installed as a result of implementing the proposed project, construction activities such as digging, earthmoving, grading, slab pouring, or paving could occur if the proposed site for the new equipment is not suitable in its present form (e.g., graded with a foundation slab). Tables 4.5-2 and 4.5-3 contain a summary of the estimates of plot space needed per facility for the refinery and non-refinery sectors, respectively. Table 4.5-4 contains a summary of the estimates of plot space needed for all 20 facilities.

Based on the consultant's surveys of the affected facilities, if all affected facilities conduct site preparation activities, the total amount of disturbed area for all of the 20 facilities combined is estimated to be 102,495 square feet (2.35 acres). For a worst-case analysis, all affected facilities are assumed to conduct overlapping site preparation activities, though as a practical matter, not much overlap of site preparation activities would be expected since there are several years from when the first and last NOx RTC shave occurs (e.g., between 2016 and 2022). Further, depending on the scale, site preparation typically can take anywhere from two days to one month. Therefore, it is unlikely that all affected facilities will do site preparation both in the same month of the same year. The largest parcel of land to be potentially disturbed at any one facility could occur at Refinery 5 and is approximately 24,943 square feet which represents almost 25 percent of the total area to be disturbed.

Instead of installing new equipment, there are a few facility operators that may choose to modify or replace their existing NOx control equipment. In these cases, site preparation activities are not expected because the existing foundation and the existing equipment are expected to be reused in their current location and current plot space. Therefore, no water for dust suppression purposes is expected to be needed for these facilities for any construction upgrades to existing NOx control equipment.

Table 4.5-2
Potential Plot Space Needed For Proposed NOx Control Technologies at Refinery Facilities

Refinery ID	Potential NOx Control per Equipment/Source Category	Plot Space Needed for Proposed Controls (square feet)
1	SRU/TGU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 14 SCRs 15 NH3 Storage Tanks	3,953 + 0 + 2,464 + 6,000 + **12,417**
2	Coke Calciner: 1 Ultracat DGS or 1 LoTOx™ with WGS	**1,200**
3	Boilers/Heaters: 2 SCRs 14 NH3 Storage Tanks	352 + 800 + **1,152**
4	FCCU: 1 LoTOx™ with WGS Gas Turbine: 1 SCR Boilers/Heaters: 6 SCRs 6 NH3 Storage Tanks	1,575 + 0 + 888 + 2,400 + **4,863**
5	FCCU: 1 SCR SRU/TGU: 2 LoTOx™ with 2 WGSs SRU/TGU: 1 SCR Gas Turbine: 3 SCRs Boilers/Heaters: 12 SCRs 15 NH3 Storage Tanks	2,475 + 11,860 + 2,475 + 0 + 4,608 6,000 + **27,418**
6	FCCU: 1 SCR SRU/TGU: 1 LoTOx™ with WGSs Gas Turbine: 1 SCR Boilers/Heaters: 15 SCRs 17 NH3 Storage Tanks	2,475 + 5,930 + 0 + 5,760 6,800 **20,965**
7	FCCU: 1 LoTOx™ without WGS Gas Turbine: 1 SCR Boilers/Heaters: 9 SCRs 10 NH3 Storage Tanks	384 + 0 + 3,456 + 4,000 + **7,840**
8	SRU/TGU: 1 LoTOx™ with WGS Boilers/Heaters: 9 SCRs 9 NH3 Storage Tanks	3,953 + 3,456 + 3,600 + **11,009**
9	FCCU: 1 LoTOx™ with WGS Boilers/Heaters: 7 SCRs 7NH3 Storage Tanks	1,575 + 2,688 + 2,800 **7,063**
	TOTAL	**93,927**

Table 4.5-3
Potential Plot Space Needed For Proposed NOx Control Technologies
at Non-Refinery Facilities

Non-Refinery ID	Potential NOx Control per Equipment/Source Category	Plot Space Needed for Proposed Controls (square feet)
1	ICEs: 5 SCRs Gas Turbines: 3 SCRs 2 NH3 Storage Tanks	880 + 528 + 800 **2,208**
2	ICEs: 6 SCRs Gas Turbines: 4 SCRs 2 NH3 Storage Tanks	1,056 + 704 + 800 **2,560**
3	ICEs: 5 SCRs 1 NH3 Storage Tank	880 + 400 **1,280**
4	Gas Turbine: 1 SCR 1 NH3 Storage Tank	176 + 400 **576**
5	Gas Turbines: 2 SCRs 1 NH3 Storage Tank	352 + 400 **752**
6	Gas Turbine: 1 SCR 1 NH3 Storage Tank	176 + 400 **576**
7	Gas Turbines: 2 SCRs 1 NH3 Storage Tank	352 + 400 **752**
8	Glass Melting Furnace: 2 SCRs 2 NH3 Storage Tanks	352 + 800 **1,152**
9	Sodium Silicate Furnace: 1 Tri-Mer 1 NH3 Storage Tank	640 + 400 **1,040**
10	Metal Heat Treating Furnace: 1 SCR 2 NH3 Storage Tanks	176 + 800 **976**
11	Gas Turbine: 1 SCR (replacement of existing) 1 NH3 Storage Tank (existing)	0 + 0 **0**
	TOTAL	**12,272**

Table 4.5-4
Total Plot Space Needed By All 20 Facilities

Sector	Plot Space Needed for Proposed Controls (square feet)	Total Acreage
9 Refineries	93,927	2.16
11 Non-Refineries	12,272	0.28
TOTAL	**106,199**	**2.44**

The amount of plot spaced needed per facility directly correlates to how much soil may be disturbed and how much water may be needed for dust suppression during construction. To comply with the dust suppression requirements in SCAQMD Rule 403 – Fugitive Dust, during site preparation activities, some water is expected to be used. For example, one water truck per affected facility may be needed for dust suppression activities during the initial site preparation/earth moving portion of the proposed project. One water truck can hold approximately 6,000 gallons for dust control and it can be refilled over the course of the day if more than 6,000 gallons is needed. To minimize fugitive dust, a minimum of watering two times per day is required. However, on windy days, it may be necessary to conduct a third water application.

At a peak watering rate of three applications per day, Table 4.5-5 shows that the peak amount of water that could be used for site preparation/dust suppression is 12,501 gallons per day if all 20 facilities were under construction and disturbing the soil at the same time. The calculations in Table 4.5-5 assume watering three times per day during construction, with 1/16 inch depth of water applied per visit, and 451 gallons of water applied per cubic foot of disturbed area.

Table 4.5-5

Total Amount of Water Needed By All 20 Facilities For Dust Suppression

Sector	**Water Needed for Dust Suppression** (gallons/day)
9 Refineries	10,674
11 Non-Refineries	1,377
TOTAL	**12,501**

The potential increase in water use for the facilities that may need to conduct watering for dust suppression activities is below the SCAQMD's significance thresholds of five million gallons per day of total water (e.g., potable, recycled, and groundwater) and 262,820 gallons per day of potable water. It is important to note that due to the need to quickly construct a proper foundation for the proposed control equipment, earth moving activities during site preparation are expected to be of a short duration lasting from two to three days to no longer than one month per facility. As such, the corresponding dust control activities are also not expected to last longer than one month per facility. Further, water used for dust suppression does not have to be of potable quality, but can be recycled water. Nonetheless, the amount of water that may be used on a daily basis for dust suppression activities during construction is less than significant.

Once constructed, but prior to operation, additional water is expected to be used to hydrostatically (pressure) test all storage tanks and pipelines to ensure each structure's integrity and wastewater may be created during the testing. Pressure testing or hydrotesting is typically a one-time event, unless a leak is found. Similar to dust suppression, water used for pressure testing does not have to be of potable quality, but can be recycled water. In addition, water used during hydrotesting can be sent somewhere else within a facility for future re-use. For example, in the Final Negative Declaration for the Phillips 66 Los

Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project[1], water used during hydrotesting of the crude storage tank was later sent to hydrotest another smaller tank being built as part of the project. Afterwards, the water from the hydrotesting was transferred to a fire water tank that supplies process water to the refinery so that no water was wasted as a result of hydrotesting.

Tables 4.5-6 and 4.5-7 contain a summary of the number of NH3 storage tanks that may be constructed at each facility, the number of tanks that may have overlapping construction activities per facility, and the amount of water that may be needed to hydrotest each tank for the refinery and non-refinery sectors, respectively. Table 4.5-8 contains a summary of the peak water demand for hydrotesting one tank per facility at all 20 facilities in one day as well as the total amount of water needed for hydrotesting the entire project.

Table 4.5-6

Total Amount of Water Needed for Hydrotesting Storage Tanks at Refinery Facilities

Refinery ID	**No. of NH3 storage tanks needed**	**Size of NH3 storage tanks needed (gallons)**	**Number of Tanks Overlapping Construction per day** *(assumes 1/3rd of total number of tanks)*	**Gallons of Water Needed to Hydrotest during Overlap**	**Gallons of Water Needed to Hydrotest for Entire Project**
1	15	11,000	5	55,000	165,000
2	1	11,000	1	11,000	11,000
3	2	11,000	1	11,000	22,000
4	6	11,000	2	22,000	66,000
5	17	11,000	6	66,000	187,000
6	17	11,000	6	66,000	187,000
7	10	11,000	3	33,000	110,000
8	9	11,000	3	33,000	99,000
9	7	11,000	2	22,000	77,000
TOTAL	**84**		**29**	**319,000**	**924,000**

[1] SCAQMD, Final Negative Declaration for the Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, SCH No. 2013091029, December 2014, p. 2-57. http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/phillips-66-fnd.pdf?sfvrsn=2

Table 4.5-7
Total Amount of Water Needed for Hydrotesting Storage Tanks at Non-Refinery Facilities

Non-Refinery ID	No. of NH3 storage tanks needed	Size of NH3 storage tanks needed (gallons)	Number of Tanks Overlapping Construction per day	Gallons of Water Needed to Hydrotest during Overlap	Gallons of Water Needed to Hydrotest for Entire Project
1	2	3,000	2	6,000	6,000
2	2	1,500	2	3,000	3,000
3	1	1,000	1	1,000	1,000
4	1	2,000	1	2,000	2,000
5	1	2,000	1	2,000	2,000
6	1	2,000	1	2,000	2,000
7	1	2,000	1	2,000	2,000
8	2	1,062	2	2,124	2,124
9	1	600	1	600	600
10	2	2,000	2	4,000	4,000
11	1	10,000	1	10,000	10,000
TOTAL	**15**		**15**	**34,724**	**34,724**

Table 4.5-8
Total Amount of Water Needed By All 20 Facilities For Hydrotesting

Sector	**Peak Daily Water Needed for Hydrotesting** (gallons/day)	**Total Water Needed for Hydrotesting Entire Project** (gallons/project)
9 Refineries	319,000	924,000
11 Non-Refineries	34,724	34,724
TOTAL	**353,724**	**958,724**

As shown in Table 4.5-7, the potential increase in water use for all 20 facilities conducting hydrotesting activities in one day is greater than the SCAQMD’s significance threshold of 262,820 gallons per day of potable water. Thus, the amount of potable water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is potentially significant, primarily due to the refinery sector. However, the potential increase in water use for all 20 facilities conducting hydrotesting activities for the entire project is below the SCAQMD’s significance threshold of five million gallons per day of total water. Thus, the amount of total water that may be used for hydrotesting activities post-construction but prior to operation for the entire project is less than significant.

Construction Water Quality

Any wastewater generated from hydrotesting or pressure testing is expected to flow to each affected facility's wastewater treatment or collection system and recycled or discharged after treatment with process wastewater. Thus, wastewater generation from pressure testing activities is not expected to affect groundwater quality. Further, the volume of wastewater that will be generated from pressure testing is equivalent to the amount of water needed for hydrotesting, as shown in Table 4.5-8. Relative to the potential increases in wastewater generation during operation over the long-term as shown in Table 4.5 10, the volume of wastewater that will be generated during hydrotesting on the short-term is expected to be minimal and within the capacity of each facility's wastewater treatment and collection systems.

Further, because the total amount of disturbed area for all of the facilities combined is estimated to be 106,199 square feet (2.44 acres) with the peak amount of area to be disturbed at Refinery 5 at 27,418 square feet (0.63 acre), the proposed construction activities will disturb less than one acre at all 20 facilities. This means that a NPDES General Permit for Storm Water Discharges Associated with Construction Activity, also referred to as a Storm Water Construction Permit, would not be required for any of the affected facilities. Because the proposed project is expected to disturb substantially less than one acre per facility, on-site collection of storm water in each facility's storm water collection system is expected to be about the same as the amount currently collected.

Therefore, less than significant impacts are expected from wastewater generation or storm water during construction or during hydrotesting post-construction.

Construction Conclusion

Construction Dust Suppression: Less than significant adverse water demand and wastewater impacts are expected during construction of the proposed project.

Hydrotesting Post-Construction: Significant adverse water demand impacts from hydrotesting are expected. Less than significant impacts are expected from wastewater generation or storm water from hydrotesting.

4.5.3.2 Mitigation of Construction Hydrology and Water Quality Impacts

Construction Dust Suppression: Less than significant adverse impacts associated with hydrology (water demand) and water quality are expected from the proposed project during construction, so no mitigation measures during construction are required.

Hydrotesting Post-Construction – Water Demand: Significant adverse water demand impacts from hydrotesting are expected, so mitigation measures during hydrotesting are required. For any facility that installs NOx control equipment that also requires the installation of support equipment, such as a storage tank or other equipment, to be installed and hydrotested as part of the proposed project, SCAQMD staff, pursuant to mitigation measures, will require~~s~~ that the facility operators utilize both current supplies and future supplies of recycled water in accordance with the California Water Code, and if available, pursuant to the HRRWP or other recycled water pipeline, if available, to conduct hydrotesting~~ of the storage tank~~. Alternately, facility operators may substitute the use of purchased recycled water with non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility. Based on the preceding discussion, the following water demand mitigation measures during hydrotesting will apply to the proposed project:

HWQ-1 When support equipment such as a storage tank or other equipment is installed to support operations of installed NOx control equipment and hydrotesting is required prior to ~~its~~ operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, i~~I~~n the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used, the facility operator is required to submit two ~~a~~ written declarations with each ~~the~~ application for a Permit to Construct for the NOx control equipment and any support equipment such as ~~the~~ storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered ~~supplied~~ to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

Hydrotesting Post-Construction – Water Quality: Less than significant impacts are expected from wastewater generation or storm water from hydrotesting, so no water quality mitigation measures are required during hydrotesting.

4.5.3.3 Remaining Construction Hydrology and Water Quality Impacts After Mitigation

Construction Dust Suppression: The hydrology and water quality analysis concluded that potential hydrology (water demand) and water quality impacts during construction would be less than significant, so no mitigation measures are required during construction. Thus, hydrology and water quality impacts during construction remain less than significant.

Hydrotesting Post-Construction – Water Demand: The hydrology analysis concluded that potential water demand impacts during hydrotesting would be significant, so mitigation measures are required during hydrotesting. The water demand analysis during hydrotesting shows that the potential increase in potable water use cannot be fully satisfied ~~supplied~~ either with all ~~potable water or with a combination of~~ recycled water or ~~and~~ a combination of non-potable water such as process water and recycled water, since some potable water may still be required for certain facilities. The use of non-potable water such as recycled water and diverted process water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water or diverted non-potable process water are required to use recycled water, if available, or diverted non-potable process water. For example, Refineries 1, 5 and 6 currently have access to recycled water and Refineries 4 and 9 may have future access to recycled water (see Subsection 4.5.3.4 for a more detailed discussion). Further, the use of other non-potable process water temporarily diverted from elsewhere within the facility is another option that can help substantially reduce the potable water demand impacts to a less than significant level if facility operators that have a way to divert non-potable process water to a location within the facility where hydrotesting will be conducted. For example, for the Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, water for conducting hydrotesting was satisfied with non-potable groundwater that was temporarily diverted from the fire water tank[2]. In addition, the reuse of hydrotest water, whether the source is recycled water or other non-potable water, for multiple tanks, for example, for other uses within each facility can also help substantially reduce~~d~~ the water demand impacts to a less than significant level. However, because there is no absolute guarantee at the time of this writing that ~~future supplies of potable water or~~ recycled water or other non-potable will be available to all of the affected facilities, the analysis conservatively assumes that potable water may be needed. Therefore, the proposed project will remain significant after mitigation for water demand during hydrotesting.

Hydrotesting Post-Construction – Water Quality: Since less than significant impacts are expected from wastewater generation or storm water from hydrotesting, no water quality mitigation measures are required during hydrotesting. Thus, water quality impacts during hydrotesting remain less than significant.

4.5.3.4 Hydrology and Water Quality Impacts During Operation

Of the technologies proposed as BARCT for NOx control, only WGSs utilize water and generate wastewater as part of their day-to-day operations. For this reason, only WGS technology was identified as having the potential to generate adverse hydrology and water quality operational impacts. The potential adverse affects on hydrology (water demand) and wastewater will be the focus of the evaluation in this subchapter. The analysis shows that WGS technology may be installed for two FCCUs, five SRU/TGUs, and one coke calciner for the refinery sector. However, for the non-refinery sector, WGS technology was not identified as BARCT for the affected equipment. Table 4.5-9 summarizes the estimated number of WGSs that may be installed for each ~~the~~ refinery, the amount of increased water demand, and the amount of increased wastewater to be generated as a result of implementing the proposed project.

[2] SCAQMD, Final Negative Declaration for: Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, SCH No. 2013091029, December 12, 2014, p. 2-57. http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/phillips-66-fnd.pdf?sfvrsn=2

Table 4.5-9
Estimated Number of WGSs to be Installed for the Refinery Sector and Associated Water Use/Wastewater Generation

Refinery ID	Potential NOx Control per Equipment/Source Category	Potential Increase in Operational Water Demand (gal/day)	Potential Increase in Wastewater Generation (gal/day)
1	SRU/TGU: 1 LoTOx™ with WGS	70,000	13,973
2	Coke Calciner: 1 LoTOx™ with WGS	40,896	16,992
4	FCCU: 1 LoTOx™ with WGS	49,315	21,918
5	SRU/TGU: 2 LoTOx™ with 2 WGSs	219,178	98,630
6	SRU/TGU: 1 LoTOx™ with WGSs	109,589	49,315
8	SRU/TGU: 1 LoTOx™ with WGS	70,000	13,973
9	FCCU: 1 LoTOx™ with WGS	43,836	21,918
	TOTAL	**602,814**	**236,719**

<u>Water Demand</u>
As summarized in Table 4.5-10, each affected refinery provided its water demand baseline and these water usage rates were compared to each facility's estimated potential increase in water demand that may result from implementing the proposed project. The peak percentage increase from baseline levels when compared to the proposed project was approximately 3.70 percent (Refinery 2) but most of the affected facilities have a potential increase in water demand from less than one to two percent above each facility's baseline. The overall increase in water demand for is 1.31 percent above the total water use baseline for all of the affected refineries combined.

Table 4.5-10
Potential Increases in Operational Water Demand per Affected Refinery

Refinery ID	Proposed Control Technology That Utilizes Water	Potential Increase in Water Use (MMgal/day)	Current Facility Water Use (MMgal/day)	Percentage Increase Above Baseline
1	SRU/TGU: 1 LoTOx™ with WGS	0.07	12.5	0.56%
2	Coke Calciner: 1 LoTOx™ with WGS	0.04	1.08	3.70%
4	FCCU: 1 LoTOx™ with WGS	0.05	5.76	0.87%
5	SRU/TGU: 2 LoTOx™ with 2 WGSs	0.21	10.75	1.95%
6	SRU/TGU: 1 LoTOx™ with WGSs	0.11	10.32	1.07%
8	SRU/TGU: 1 LoTOx™ with WGS	0.07	2.88	2.43%
9	FCCU: 1 LoTOx™ with WGS	0.04	2.5	1.60%
	TOTAL*	**0.60**	**45.79**	**1.31%**

*Total adjusted due to rounding

It is important to note that operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the installation of WGS technology along with the corresponding increased water demand and wastewater generation projections that were originally contemplated for one of the two FCCUs (e.g., Refineries 4 and 9) identified in Tables 4.5-9 and 4.5-10 are no longer expected to occur. Thus, the potential increase in operational water demand is expected to be less. To protect the identity of the refinery in this document, the revised potential increase in operational water demand will be presented as a range, from 553,499 gallons per day to 558,978 gallons per day, instead of 602,814 gallons per day as shown in Table 4.5-9.

As explained in Subchapter 3.5 – Hydrology and Water Quality, Governor Brown proclaimed a State of Emergency for California due to unprecedented drought conditions. New laws went into effect to begin regulating groundwater by adding restrictions on pumping in some areas to prevent aquifers from dwindling and wells from running dry. Water districts, in response to the drought, have also taken actions throughout the state such as: 1) asking for voluntary reductions; 2) imposing mandatory restrictions or declaring a local emergency; 3) imposing agricultural rationing; 4) imposing drought rates, surcharges and fines; 5) limiting new development and requiring water efficient landscaping; 6) implementing a conservation campaign; 7) stopping water pumping from various streams; and, 8) adjusting water contract allocations. In addition, water shortages have prompted cities to begin infrastructure improvements to secure future water supplies.

Because of the drought and the uncertainty of future water supplies, it was ~~is~~ not clear at the~~is~~ time of the release of the Draft PEA whether water suppliers would be able to accommodate the additional operational water demand if the proposed project goes forward, especially if potable water or groundwater would be relied upon to supply the water demand. Subsequently, SCAQMD staff has been able to verify that projected water deliveries of potable water and recycled water to industrial sources will be able to supply the potential water demand needs of the proposed project. As part of making a determination if water supplies will be sufficient for the proposed project, the availability of recycled water is an important factor. Of the ~~seven~~ affected refineries, three facilities (e.g., Refineries ~~Facilities~~ 1, 5, and 6) currently access recycled water from the Harbor Refineries Recycled Water Pipeline (HRRWP) which is maintained by the Los Angeles Department of Water and Power (LADWP), in conjunction with the West Basin Municipal Water District (WBMWD). The LADWP/WBMWD currently provides 35 million gallons per day (MMgal/day) of recycled water to its customers, which include Refineries 1, 5, and 6. The WBMWD is also in the process of expanding its Hyperion Pump Station to accommodate a throughput of 70 MMgal/day of source water which would result in about 55 to 60 MMgal/day of saleable recycled water if, and when needed to accommodate any increased need by their customers[3]. Thus, s~~S~~hould operators of these three facilities commit to utilizing recycled water in lieu of potable water to satisfy the water demand for the NOx control equipment, then the LADWP/WBMWD would be able to supply the additional water (e.g., 398,767 gallons per day or approximately 71 ~~66~~ percent of the projected water demand).

[3] Personal communications with Joe Walters, West Basin Municipal Water District, August 3, 2015 and November 4, 2015.

At the time of writing the~~is~~ Draft PEA, SCAQMD was ~~has~~ not ~~been~~ able to confirm whether three refineries (e.g., Refineries ~~Facilities~~ 4, 8 and 9) have connected to the HRRWP to access its supply of recycled water. To date, none of these refineries have connected to the HRRWP. However, Refinery 4 is in the process of finalizing an agreement with WBMWD to acquire 2,240 acre-feet/year (AF/yr)[4] of recycled water (equivalent to two MMgal/day) to replace its current potable water use with recycled water by 2018. In addition, Refineries 4, 8, and 9 are currently in talks with the LADWP and WBMWD to negotiate options for replacing as much as 11,100 AF/yr (equivalent to approximately 9.9 MMgal/day) of current potable water use with recycled water instead via the HRRWP[5]. Thus, if Refineries 4, 8 and 9 need additional recycled water in response to this proposed project, the LADWP/WBMWD has the capacity to provide additional recycled water as necessary[2].

Table 4.5-11 identifies each refinery's suppliers of purchased potable and recycled at the wholesale and retail level.

Table 4.5-11
Purchased Water Suppliers per Affected Refinery

Refinery ID	**Purchased Water Supplier**
1 and 8	CWS (retailer); WBMWD (wholesaler)
2	LBWD
4 and 9	LADWP (retailer); MWD (wholesaler)
5	City of El Segundo (retailer); WBMWD (wholesaler)
6	City of Torrance (retailer); WBMWD (recycled wholesaler)

Key:
CWS = California Water Service
WBMWD = West Basin Municipal Water District
LBWD = Long Beach Water Department
LADWP = Los Angeles Department of Water and Power
MWD = Metropolitan Water District

A 2010 Urban Water Management Plan (UWMP) is required to be adopted by July 1, 2011 (California Water Code §10608.20) for each urban water supplier to demonstrate the availability of current and projected water supplies. Tables 4.5-12 through 4.5-18 summarize the water delivery projections for the various suppliers to the refinery facilities that have a projected increase in water demand.

[4] 1 acre-foot = 325,851 gallons

[5] City of Los Angeles, Inter-Departmental Correspondence to City Council From Los Angeles Department of Water and Power and Los Angeles Department of Public Works Bureau of Sanitation, Council File No. 15-0018 Harbor Refineries Pipeline Project/Advanced Water Purification Facility/Water Supply Efforts, April 10, 2015. https://cityclerk.lacity.org/lacityclerkconnect/index.cfm?fa=ccfi.viewrecord&cfnumber=15-0018

Table 4.5-12

Projected Water Deliveries to Industrial Sources by the California Water Service

Water Type	Volume of Water Deliveries to Industrial Sources (in AF)					
	Actual Deliveries in 2010	Projected Deliveries for 2015	Projected Deliveries for 2020	Projected Deliveries for 2025	Projected Deliveries for 2030	Projected Deliveries for 2035
Potable[1]	10,953	11,185	10,899	11,807	12,762	13,762
Recycled[2]	5,251	4,134	4,586	5,088	5,646	6,264
TOTAL	16,204	15,319	15,485	16,895	18,408	20,026

AF = acre feet (1 acre-foot = 325,851 gallons)

[1] California Water Service Company, 2010 Urban Water Management Plan, Dominguez District, June 2011, Tables 3.3-2 through 3.3-6, pp. 33 - 35. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/CA%20Water%20Service%20Co%20-%20Dominguez%20District/

[2] California Water Service Company, 2010 Urban Water Management Plan, Dominguez District, June 2011, Table 3.4-1, p. 41. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/CA%20Water%20Service%20Co%20-%20Dominguez%20District/

Table 4.5-13

Projected Water Deliveries to Industrial Sources by the West Basin Municipal Water District

Water Type	Volume of Water Deliveries to Industrial Sources (in AF)					
	Actual Deliveries in 2010	Projected Deliveries for 2015	Projected Deliveries for 2020	Projected Deliveries for 2025	Projected Deliveries for 2030	Projected Deliveries for 2035
Potable[1, *]	16,739	18,930	18,948	18,797	18,659	18,569
Recycled[2]	14,182	16,368	33,882	33,882	37,382	37,382
TOTAL	30,921	35,298	52,830	52,679	56,041	55,951

AF = acre feet (1 acre-foot = 325,851 gallons)

[*] The potable water data is for all customers, not just industrial sources.

[1] West Basin Municipal Water District, 2010 Urban Water Management Plan, May 2011. Table 3-4 for City of El Segundo, p. 3-5. http://www.water.ca.gov/mwg-internal/de5fs23hu73ds/progress?id=GfB6eYbb-msHgQl5dmQklHEnuqh4ELnWDALQusESbGY

[2] West Basin Municipal Water District, 2010 Urban Water Management Plan, May 2011. Table 3-3, p. 3-5. http://www.water.ca.gov/mwg-internal/de5fs23hu73ds/progress?id=GfB6eYbb-msHgQl5dmQklHEnuqh4ELnWDALQusESbGY

According to the 2010 UWMPs for the California Water Service (CWS) and the West Basin Municipal Water District (WBMWD) that were prepared in accordance with the California Water Code §10608.20 and as summarized in Tables 4.5-12 and 4.5-13, the potable water delivery projections to their industrial customers show a long-term projected increase in potable water supply with a slight tapering in supply occurring between years 2025 and 2035 that will be offset by increased deliveries of recycled water instead. These two water suppliers provide water to Refineries 1 and 8. Based on the short- and long-term growth projections for potable and recycled water supplies for the CWS and WBMWD, SCAQMD staff believes that the potential increased water demand of 140,000 gallons per day (equivalent to approximately 157 AF/yr) for Refineries 1 and 8 can be accommodated with either potable or recycled water.

Table 4.5-14
Projected Water Deliveries to Industrial Sources
by the Los Angeles Department of Water and Power

Water Type	Volume of Water Deliveries to Industrial Sources (in AF)					
	Actual Deliveries in 2010	Projected Deliveries for 2015	Projected Deliveries for 2020	Projected Deliveries for 2025	Projected Deliveries for 2030	Projected Deliveries for 2035
Potable[1]	19,166	18,600	16,852	14,708	12,634	10,513
Recycled[2]	6,703	20,000	20,400	27,000	29,000	29,000
TOTAL	25,869	38,600	37,252	41,708	41,634	39,513

AF = acre feet (1 acre-foot = 325,851 gallons)

[1] Los Angeles Department of Water and Power, Urban Water Management Plan, 2010, Exhibit 2J, page 45. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Los%20Angeles%20Department%20of%20Water%20and%20Power/

[2] Los Angeles Department of Water and Power, Urban Water Management Plan, 2010, Exhibits 4J and 4L, pp. 97-98. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Los%20Angeles%20Department%20of%20Water%20and%20Power/

Table 4.5-15
Projected Water Deliveries to Municipal and Industrial
Sources by the Metropolitan Water District

Water Type	Volume of Water Deliveries to Municipal and Industrial Sources (in MAF)					
	Actual Deliveries in 2010 [1]	Projected Deliveries for 2015 [2]	Projected Deliveries for 2020 [2]	Projected Deliveries for 2025 [2]	Projected Deliveries for 2030 [2]	Projected Deliveries for 2035 [2]
Potable	4,663	5,004	5,232	5,409	5,572	5,715
Recycled	277	340	370	390	407	423
TOTAL	4,940	5,344	5,602	5,799	5,979	6,138

MAF = thousand acre feet (1 acre-foot = 325,851 gallons)

[1] Metropolitan Water District of Southern California, 2010 Regional Urban Water Management Plan, November 2010, Table A-2, p. A.4-72. http://mwdh2o.com/PDF_About_Your_Water/2.4.2_Regional_Urban_Water_Management_Plan.pdf.

[2] Metropolitan Water District of Southern California, 2010 Regional Urban Water Management Plan, November 2010, Table 2-7, p. 2-13. http://mwdh2o.com/PDF_About_Your_Water/2.4.2_Regional_Urban_Water_Management_Plan.pdf

According to the 2010 UWMPs for the Los Angeles Department of Water and Power (LADWP) and the Metropolitan Water District (MWD) that were prepared in accordance with the California Water Code §10608.20 and as summarized in Tables 4.5-14 and 4.5-15, the potable and recycled water delivery projections to their municipal and industrial customers show a gradual increase in supply occurring between years 2010 and 2035. These two water suppliers provide water to Refineries 4 and 9. As explained earlier, because one of these two refineries has plans to shut down its FCCU, only one of the two WGSs contemplated for the two FCCUs is now projected to occur. Thus, only the water demand for one of the two refineries is also expected to occur (e.g., either 43,836 gallons per day or 49,315 gallons per day). Based on the short- and long-term projections for potable and recycled water supplies for the LADWP and MWD, SCAQMD staff believes that the potential increased water demand of either 43,836 gallons per day or 49,315 gallons per day (equivalent to approximately 49 AF/year to 55 AF/yr) for either Refinery 4 or 9 can be accommodated with either potable or recycled water.

Table 4.5-16
Projected Water Deliveries to Industrial Sources by the City of El Segundo

Water Type	**Volume of Water Deliveries to Industrial Sources (in AF)**					
	Actual Deliveries in 2010	**Projected Deliveries for 2015**	**Projected Deliveries for 2020**	**Projected Deliveries for 2025**	**Projected Deliveries for 2030**	**Projected Deliveries for 2035**
Potable[1]	3,692	3,166	2,898	2,989	3,082	N/A
Recycled[2]	8,615	8,750	8,750	8,750	8,750	N/A
TOTAL	12,307	11,916	11,648	11,739	11,832	N/A

AF = acre feet (1 acre-foot = 325,851 gallons)
N/A = data not available
[1] City of El Segundo, 2010 Urban Water Management Plan, Tables 3.2.3 through 3.2.6, pp. 3-11 to 3-12. http://www.elsegundo.org/civicax/filebank/blobdload.aspx?BlobID=14356
[2] City of El Segundo, 2010 Urban Water Management Plan, Table 3.2.8, p. 3-13. http://www.elsegundo.org/civicax/filebank/blobdload.aspx?BlobID=14356

According to the 2010 UWMPs for the WBMWD and the City of El Segundo that were prepared in accordance with the California Water Code §10608.20 and as summarized in Tables 4.5-13 and 4.5-16, the City of El Segundo's potable water delivery projections to their industrial customers show a gradual tapering in potable water supply occurring between years 2015 and 2030 that will be offset by deliveries of recycled water instead. However, the WBMWD's potable and recycled water delivery projections show an increase over the same timeframe (gradual for potable water, substantial increase for recycled water). These two water suppliers provide water to Refinery 5, which currently receives recycled water. Based on the short- and long-term projections for potable and recycled water supplies for the WBMWD and the City of El Segundo, SCAQMD staff believes that the potential increased water demand of 219,178 gallons per day (equivalent to approximately 246 AF/year) can be accommodated with either potable or recycled water.

Table 4.5-17

Projected Water Deliveries to Industrial Sources by the City of Torrance

Water Type	Volume of Water Deliveries to Industrial Sources (in AF)					
	Actual Deliveries in 2010	Projected Deliveries for 2015	Projected Deliveries for 2020	Projected Deliveries for 2025	Projected Deliveries for 2030	Projected Deliveries for 2035
Potable[1, *]	16,471	29,007	29,007	29,007	29,007	29,007
Recycled[2]	6,161	6,650	6,650	7,150	7,150	7,150
TOTAL	22,632	35,657	35,657	36,157	36,157	36,157

AF = acre feet (1 acre-foot = 325,851 gallons)

* The pot able water data is for all customers, not just industrial sources.

1 City of Torrance, 2010 Urban Water Management Plan, July 2011, Table 2.6, page 2-10. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Torrance,%20City%20of/00%20Final%20Torrance%202010%20UWMP_07-28-11.pdf

2 City of Torrance, 2010 Urban Water Management Plan, July 2011, Tables 2.5 and 2.6, page 2-10. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Torrance,%20City%20of/00%20Final%20Torrance%202010%20UWMP_07-28-11.pdf

According to the 2010 UWMPs for the WBMWD and the City of Torrance that were prepared in accordance with the California Water Code §10608.20 and as summarized in Tables 4.5-13 and 4.5-17, the City of Torrance's potable water delivery projections to their industrial customers show an increase in potable and recycled water supply when compared to deliveries in 2010. The WBMWD's potable and recycled water delivery projections also show an increase over the same timeframe (gradual for potable water, substantial increase for recycled water). These two water suppliers provide water to Refinery 6, which currently receives recycled water. Based on the short- and long-term projections for potable and recycled water supplies for the WBMWD and the City of Torrance, SCAQMD staff believes that the potential increased water demand of either 109,589 gallons per day (equivalent to approximately 123 AF/year) can be accommodated with either potable or recycled water.

Table 4.5-18
Projected Water Deliveries to Commercial and Industrial Sources*
by the Long Beach Water Department

Water Type	Volume of Water Deliveries to Commercial and Industrial Sources (in AF)					
	Actual Deliveries in 2010	Projected Deliveries for 2015	Projected Deliveries for 2020	Projected Deliveries for 2025	Projected Deliveries for 2030	Projected Deliveries for 2035
Potable[1]	14,397	14,687	14,694	14,695	14,549	14,536
Recycled[2]	1,136	3,800	4,800	6,200	6,300	6,400
TOTAL	15,533	18,487	19,494	20,895	20,849	20,936

AF = acre feet (1 acre-foot = 325,851 gallons)
* The Long Beach Water Department bills water sold to the Port of Long Beach under both the commercial and industrial source categories.
[1] Long Beach Water Department, 2010 Urban Water Management Plan, September 2011, Attachment B, Tables 4 through 7, page 4. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Long%20Beach%20Water%20Department/Attach_B.pdf
[2] Long Beach Water Department, 2010 Urban Water Management Plan, September 2011, Attachment B, Tables 23 and 24, page 9. http://www.water.ca.gov/urbanwatermanagement/2010uwmps/Long%20Beach%20Water%20Department/Attach_B.pdf

~~Further, Facility~~ Refinery 2 is not located near the HRRWP nor any other recycled water pipeline so it is unlikely that Refinery ~~Facility~~ 2 would be able to obtain recycled water should facility operators choose to install a WGS and instead, would need to satisfy the water demand with potable water. According to the Long Beach Water Department's (LBWD's) 2010 UWMP that was prepared in accordance with the California Water Code §10608.20, the potable water delivery projections to their industrial and commercial customers show a long-term projected increase in potable water supply with a slight tapering occurring in years 2030 and 2035 to reflect offsetting by increased deliveries of recycled water to other customers currently being supplied by LBWD with potable water. Based on LBWD's short- and long-term projections for potable and recycled water supplies, SCAQMD staff believes that the potential increased water demand of 40,896 gallons per day for Refinery 2 can be accommodated.

In addition, it is important to keep in mind that operators of Refinery 2 have two different types of control equipment options available for consideration. As summarized in the Tables 1-2 and 1-3 for the petroleum coke calciner source category, the BARCT NOx levels of 10 ppmv corrected for 3% oxygen can be achieved with either a WGS which uses water, or a DGS, which does not. While the analysis in this subchapter considers the technology with the worst-case impacts to water demand and water quality, for Refinery 2, installing WGS technology is not their only option. Should operators choose to install a DGS, instead of a WGS, then no water would be needed.

Thus, while the amount of water demand that would be needed to operate NOx control equipment would be 398,767 gallons per day at Refineries 1, 5 and 6 and the amount of water demand at Refineries ~~Facilities~~ 2, 4, 8, and 9 would be in the range of 113,836 gallons per day to 160,211 ~~204,047~~ gallons per day, which collectively is greater ~~less~~ than the significance threshold of 262,820 gallons per day of potable water ~~and~~ but less than the significance threshold of five million gallons per day of total water (e.g., potable, recycled, and groundwater), in consideration that Refineries 1, 5 and 6 have a high potential to use recycled water because of their current access and in light of the negotiations for recycled water at Refineries 4, 8, and 9, potable water only may be needed for a future project occurring at Refinery 2, or not at all if operators of Refinery 2 choose to install a DGS instead of a WGS. ~~it is not known at this time whether~~ In any case, the previous analysis shows that the water purveyors would be able to supply potable water to ~~for these facilities~~ Refinery 2 and to Refineries 1, 4, 5, 6, 8 and 9, if needed. Thus, using an abundance of caution, because the peak daily water demand for the proposed project exceeds the potable water threshold of 262,820 gallons per day and because ~~SCAQMD staff is unable verify whether the peak daily water demand can be satisfied with~~ recycled water is not currently available at ~~for any of the~~ R~~r~~efineries 4, 8 and 9, and no contractual commitments to increase recycled water demand above the existing recycled water baseline for ~~including~~ the three refineries that already have access to recycled water (e.g., Refineries 1, 5 and 6) have been finalized, the analysis conservatively concludeds that significant adverse impacts associated with water demand are expected from the proposed project during operation.

Water Quality

As summarized in Table 4.5-19~~11~~, each affected facility provided their wastewater discharge limits and these limits were compared to each facility's estimated potential increase in wastewater that may result from implementing the proposed project. The peak percentage increase from baseline levels when compared to the proposed project was approximately nine~~12~~ percent (Refinery 2~~9~~). An increase of 25 percent above discharge permit limits would trigger a permit revision and would be considered a significant adverse wastewater impact. Since all of the affected facilities have been shown to have a potential wastewater increase less than 25 percent, no modifications to any existing wastewater discharge permits are anticipated as a result of the proposed project. Thus, the operational impacts of the proposed project on each affected facility's wastewater discharge and the Industrial Wastewater Discharge Permit are expected to be less than significant.

Table 4.5-19~~11~~
Potential Increases in Wastewater Generation per Affected Refinery

Refinery ID	Proposed Control Technology that Generates Wastewater	Potential Increase in Wastewater Generation (MMgal/day)	Wastewater Permit Discharge Limit[1] (MMgal/day)	Percentage Increase Above Discharge Limit	Greater than 25% Increase? (Exceeds CEQA Significance Threshold?)
1	SRU/TGU: 1 LoTOx™ with WGS	0.01	8.8	0.16%	NO
2	Coke Calciner: 1 LoTOx™ with WGS	0.02	0.18	9.44%	NO
4	FCCU: 1 LoTOx™ with WGS	0.02	1.1	1.99%	NO
5	SRU/TGU: 2 LoTOx™ with 2 WGSs	0.10	7.5	1.31%	NO
6	SRU/TGU: 1 LoTOx™ with WGSs	0.05	15	0.33%	NO
8	SRU/TGU: 1 LoTOx™ with WGS	0.01	2.88	0.49%	NO
9	FCCU: 1 LoTOx™ with WGS	0.02	1.08 ~~0.18~~	2.16 ~~12.18~~%	NO
	TOTAL[2]	**0.24**	**36.54 ~~35.64~~**	**0.66~~7~~%**	

[1] Wastewater limits were obtained from each facility's wastewater permit(s). For any facility that has multiple discharge limits (i.e. dry weather, wet weather, etc.), the most conservative limit will be used for the purposes of this comparison.
[2] Total adjusted due to rounding

It is important to note that operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the installation of WGS technology along with the corresponding increased wastewater generation projections that were originally contemplated for one of the two FCCUs (e.g., Refineries 4 and 9) identified in Tables 4.5-9 and 4.5-10 are no longer expected to occur. Thus, the potential increase in operational wastewater generation is expected to be less. To protect the identity of the refinery in this document, the revised potential increase in operational wastewater generation will be reduced from 236,719 gallons per day to 214,801 gallons per day instead. Nonetheless, this reduction in operational wastewater generation will lessen the impacts further than what was analyzed at the time the Draft PEA was released for public review and comment.

No changes to each affected facility's storm water collection systems are expected because the physical changes that will occur at a facility will be associated with existing units (i.e., to install new control equipment on existing equipment or upgrading existing control equipment) and these changes will not affect existing storm water collection systems. Further, typically most of the areas likely to be affected by the proposed project are currently paved and are expected to remain paved. Any new units constructed will be curbed and the existing units will remain curbed to contain any runoff. Any runoff occurring will continue to be handled by each affected facility's wastewater system and sent to an on-site wastewater treatment system prior to discharge. The surface water runoff is expected to be handled with each facility's current wastewater collection or treatment system. Storm water runoff will be collected and discharged in accordance with each facility's discharge permit terms and conditions.

Operation Conclusion

In summary, significant adverse water demand impacts and less than significant water quality impact are expected during operation of the proposed project.

4.5.3.5 Mitigation of Operation Hydrology and Water Quality Impacts

The proposed project is expected to have significant adverse water demand impacts during operation. If significant adverse environmental impacts are identified in a CEQA document, the CEQA document shall describe feasible measures that could minimize the significant adverse impacts (CEQA Guidelines §15126.4). The following mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. If, at the time when each facility-specific project is proposed in response to the proposed project, SCAQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

Water Demand: Potentially significant adverse impacts associated with operational water demand are expected from the proposed project during operation. Thus, mitigation measures for water demand are required. For any facility that installs a WGS as part of the proposed project, SCAQMD staff requires, pursuant to mitigation measures, that the facility operators utilize both current supplies and future supplies of recycled water in accordance with the California Water Code, and if available, pursuant to the HRRWP or other recycled water pipeline, if available, for operation of a WGS. Based on the preceding discussion, the following water demand mitigation measures will apply to the proposed project:

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered ~~supplied~~ to the project.

Water Quality: Less than significant adverse impacts associated with operational water quality are expected from the proposed project during operation, so no mitigation measures during operation are required.

4.5.3.6 Remaining Operation Hydrology and Water Quality Impacts After Mitigation

Water Demand: The water demand analysis shows that the potential increase in potable water use can~~not~~ be fully satisfied ~~supplied~~ either with all potable water or with a combination of recycled water and potable water, since some potable water may still be required for certain facilities. The use of recycled water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water are required to use recycled water, if available. However, there is no absolute guarantee at the time of this writing that future supplies of ~~potable water or~~

recycled water can actually be delivered ~~will be available~~ to all of the affected facilities. Therefore, the proposed project will remain significant after mitigation for water demand.

Water Quality: The water quality analysis concluded that potential water quality impacts during operation would be less than significant, so no mitigation measures are required. Thus, water quality impacts during operation remain less than significant.

4.5.4 Cumulative Hydrology and Water Quality Impacts

Water Demand: Even though the analysis shows that there is a sufficient supply of both potable and recycled water available, b~~B~~ecause the project-specific water demand impacts have been concluded to be significant due to the uncertainty of the ability for some facilities to receive recycled water ~~supplies for some of the affected facilities~~ and in consideration of California's on-going drought, it could be argued that the potential water demand impacts from implementing the proposed project is cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1). Therefore, the proposed project is expected to generate significant adverse cumulative water demand impacts.

Water Quality: Because the project-specific water quality impacts do not exceed any applicable significance thresholds, they are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, do not generate significant adverse cumulative water quality impacts.

4.5.5 Cumulative Mitigation Measures

Water Demand: Because the project-specific water demand impacts during hydrotesting and during operation are considered to be cumulatively considerable, cumulative mitigation measures are required. Thus, the following cumulative water demand mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. If, at the time when each facility-specific project is proposed in response to the proposed project, SCAQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

HWQ-1 When support equipment such as a storage tank is installed to support operations of installed NOx control equipment and hydrotesting is required prior to ~~its~~ operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, i~~I~~n the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used,, the facility operator is required to submit two ~~a~~ written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered ~~supplied~~ to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered ~~supplied~~ to the project.

Water Quality: Because the project-specific water quality impacts during construction and operation are not considered to be cumulatively considerable, no cumulative mitigation measures are required.

SUBCHAPTER 4.6

SOLID AND HAZARDOUS WASTE

Introduction

Significance Criteria

Potential Solid and Hazardous Waste Impacts and Mitigation Measures

Cumulative Solid and Hazardous Waste Impacts

Cumulative Mitigation Measures

4.6 SOLID AND HAZARDOUS WASTE

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in adverse solid and hazardous waste impacts. The solid and hazardous waste analysis in this PEA identifies the net effect of solid and hazardous waste from implementing the proposed project.

4.6.1 Introduction

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. The different types of control devices include SCR, LoTOx^{TM} with or without a WGS, and catalyst impregnated filters with an UltraCat DGS. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx at the affected facilities, which will provide air quality and human health benefits to the public. However, installing new or modifying existing air pollution control equipment is expected to have potentially adverse solid and hazardous waste impacts. The analysis of these impacts can be found in Section 4.6.3. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse solid and hazardous waste impacts. Refer to Appendix E for the calculations used to estimate the amount of solid and hazardous waste that may be generated during construction and operation of the proposed project.

4.6.2 Significance Criteria

The proposed project impacts on solid and hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

4.6.3 Potential Solid and Hazardous Waste Impacts and Mitigation Measures

4.6.3.1 Potential Solid and Hazardous Waste Impacts During Construction

Construction activities associated with installing NOx control equipment such as demolition and site preparation/grading/excavating could generate solid waste as result of implementing the proposed project. Demolition activities could generate demolition waste while site preparation, grading, and excavating could uncover contaminated soils since the facilities affected by the proposed project are located in existing industrial areas. Excavated soil, which may be contaminated, will need to be characterized, treated, and disposed of offsite in accordance with applicable regulations. Where appropriate, the soil will be recycled if it is considered or classified as non-hazardous waste or it can be disposed of at a landfill that accepts non-hazardous waste. Otherwise, the material will need to be disposed of at a hazardous waste facility. (Potential soil contamination is addressed in the NOP/IS (see Appendix F of this PEA), in the Hazards/Hazardous Materials discussion in Section VIII. d. and was concluded to have less than significant impacts.)

Solid or hazardous wastes generated from construction-related activities at the 20 affected facilities would consist primarily of materials from the demolition of existing air pollution control equipment (if applicable) and construction associated with installing new air pollution control equipment or modifying existing air pollution control equipment. Construction-related waste can be disposed of either at a Class II (industrial) or Class III (municipal) landfill. Any equipment that is removed during demolition may be dismantled and metals may be sold as scrap. Class II landfills may accept designated and nonhazardous wastes and Class III landfills may accept nonhazardous wastes. However, there are no Class II landfills within the SCAQMD's jurisdiction. There are 31 Class III active landfills and two transformation facilities located within the district with a total capacity of 107,933 tons per day and 3,240 tons per day, respectively (see Subchapter 3.6, Tables 3.6-2 and 3.6-3)[1]. While the actual amount of construction debris that may be generated from installing new or modifying existing NOx control equipment at 20 facilities cannot be calculated, the amount of debris generated would not be expected to exceed the designated capacity of these landfills. For this reason, the construction impacts of the proposed project on waste treatment/disposal facilities are expected to be less than significant.

4.6.3.2 Mitigation of Solid and Hazardous Waste Impacts During Construction

Less than significant adverse impacts associated with solids and hazardous wastes are expected from the proposed project during construction, so no mitigation measures are required.

4.6.3.3 Remaining Solid and Hazardous Waste Impacts During Construction After Mitigation

The solids and hazardous wastes analysis concluded that potential solids and hazardous wastes impacts during construction would be less than significant, no mitigation measures were required. Thus, solids and hazardous wastes impacts during construction remain less than significant.

[1] 2012 Annual Report, Los Angeles County Countywide Integrated Waste Management Plan, Appendix E-2 Table 1 (LACDPW, 2013).

4.6.3.4 Potential Solid and Hazardous Waste Impacts During Operation

If the proposed project is implemented, solid waste may also be generated from the operation of the new NOx air pollution control equipment at both the refinery and non-refinery facilities, depending on the type of NOx control equipment employed. Tables 4.6-1 and 4.6-2 summarize the potential increased amount of solid waste expected to be generated for the refinery and non-refinery sector, respectively.

Table 4.6-1
Potential Increase in Solid Waste at Refinery Facilities

Refinery ID	**Proposed Increase in Amount of Solids Collected Due to New NOx Controls** (tons/day)	**Is the proposed increase in Solid Waste Hazardous?**	**Solid Waste will be trucked to:**
1	0.68	NO	Cement Plant for Recycling
2	0.44	NO	Cement Plant for Recycling
3	0	NO	Not Applicable
4	0.44	NO	Cement Plant for Recycling
5	1.75	NO	Cement Plant for Recycling
6	0.88	NO	Cement Plant for Recycling
7	0	NO	Not Applicable
8	0.33	NO	Cement Plant for Recycling
9	1.89	NO	Cement Plant for Recycling
Total	**6.41**		

Table 4.6-2
Potential Increase in Solid Waste at Non-Refinery Facilities

Non-Refinery ID	**Proposed Increase in Amount of Solids Collected Due to New NOx Controls** (tons/day)	**Is the proposed increase in Solid Waste Hazardous?**	**Solid Waste will be trucked to:**
1	0	NO	Not Applicable
2	0	NO	Not Applicable
3	0	NO	Not Applicable
4	0	NO	Not Applicable
5	0	NO	Not Applicable
6	0	NO	Not Applicable
7	0	NO	Not Applicable
8*	1.2	NO	Cement Plant for Recycling or Class III Landfill
9	0	NO	Not Applicable
10	0	NO	Not Applicable
11	0	NO	Not Applicable
Total	**1.2**		

* Solid waste would only be generated if the operator of non-refinery Facility 8 chooses to install an Ultracat system. However, if the operator of non-refinery Facility 8 chooses to install SCR technology, in lieu of the Ultracat system, then no solid waste would be generated.

In addition, if the proposed project is implemented, waste from spent catalyst may also be generated every five years from the operation of SCR technology at both the refinery and non-refinery facilities. For both solid waste and spent catalyst waste, it is possible that some, if not all, of the 20 affected facilities will address any increase in waste through their existing waste minimization plans. For example, some of the affected facilities in both the refinery and non-refinery sectors currently have existing catalyst-based operations and the spent catalysts are either regenerated, reclaimed or recycled, in lieu of disposal. Moreover, due to the heavy metal content and its relatively high cost, catalyst recycling can be a lucrative choice. Depending on operating conditions, it is expected that for any new SCR system installed, the spent catalysts would also be reclaimed and recycled, though it is possible that spent catalysts could be disposed of. The composition of the catalyst will determine in which type of landfill a catalyst would be disposed.

A catalyst with a metal structure would not normally be considered a hazardous waste. Instead, it would be considered a metal waste, like copper pipes, and, therefore, would not be a regulated waste requiring disposal in a Class I landfill unless it is friable or brittle. Ceramic-based catalysts are not considered friable or brittle because they typically include a fiber binding material in the catalyst material. In both cases, spent catalyst would not require disposal in a Class I landfill. Furthermore, typical catalyst materials are not considered to be water soluble, which also means they would not require disposal in a Class I landfill.

Based on the preceding discussion, it is likely that spent catalysts would be considered a "designated waste," which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (California Code of Regulations, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts would likely be disposed of in a Class III landfill that is fitted with liners.

Disposal of spent catalyst would typically involve crushing the material and encasing it in concrete prior to disposal. Since it is expected that most spent catalysts will be recycled and regenerated, it is anticipated that there will be sufficient landfill capacity in the district to accommodate disposal of any spent catalyst materials. Thus, the potential increase of solid waste generated by the air pollution control equipment operated at the 20 affected facilities that are expected to install NOx control equipment as a result implementing the proposed project may not necessarily be disposed of and, therefore, is not expected to exceed the capacity of designated landfills available to each affected facility.

As summarized in Table 4.6-1, the projected solid waste data obtained by the consultant from each affected refinery facility also indicated that approximately six tons per day of solid waste may be generated by the NOx air pollution control equipment. However, because the solid waste that may be generated at the refinery facilities is expected to be a commodity, it is also not expected to be disposed of in a landfill. Instead, the additional solid waste that may be generated from the refinery facilities will be sent to a cement plant located outside of SCAQMD's jurisdiction for recycling. In any case, even if the entire amount of solid waste that may be generated by the refinery facilities as a result of the proposed project is sent to a landfill, the amount would not exceed the capacity of these designated landfills. For this reason, the operational impacts from the refinery facilities on waste treatment/disposal facilities are expected to be less than significant.

For the non-refinery facilities, potential solid waste generation data is summarized in As summarized in Table 4.6-1, and shows that only one non-refinery facility, Facility 8, could potentially generate solid waste (approximately 1.2 tons per day) if an Ultracat system is installed. However, if operators of Facility 8 choose to install SCR technology, in lieu of an Ultracat system, then no solid waste would be generated from the SCR technology and only spent catalyst waste would be generated once every five years. Operators of Facility 8 have indicated that solid waste that may be generated from the Ultracat system could either be sent to a cement plant for recycling or to a Class III landfill. As such, the relatively small amount of solid waste that may be generated from the non-refinery sector would not exceed the capacity of the designated landfills. Thus, the operational impacts from the one non-refinery facility on waste treatment/disposal facilities are also expected to be less than significant.

Further, implementing the proposed project is not expected to hinder in any way any affected facility's ability to comply with existing federal, state, and local regulations related to solid and hazardous wastes. Based upon these considerations, the overall operational impacts of the proposed project on waste treatment/disposal facilities due to solid waste that may be generated from both refinery and non-refinery facilities are expected to be less than significant.

4.6.3.5 Mitigation of Operational Solid and Hazardous Waste Impacts

Less than significant adverse impacts associated with solids and hazardous wastes are expected from the proposed project during operation, so no mitigation measures are required.

4.6.3.6 Remaining Operational Solid and Hazardous Waste Impacts After Mitigation

The solids and hazardous wastes analysis concluded that potential solids and hazardous wastes impacts during operation would be less than significant, no mitigation measures were required. Thus, solids and hazardous wastes impacts during operation remain less than significant.

4.6.4 Cumulative Solid and Hazardous Waste Impacts

Because the project-specific solid and hazardous waste impacts do not exceed any applicable significance thresholds, they are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, do not generate significant adverse cumulative solid and hazardous waste impacts.

4.6.5 Cumulative Mitigation Measures

Because the project-specific solid and hazardous waste impacts during construction and operation are not considered to be cumulatively considerable, no cumulative mitigation measures are required.

SUBCHAPTER 4.7

TRANSPORTATION AND TRAFFIC

Introduction

Significance Criteria

Potential Transportation and Traffic Impacts and Mitigation Measures

Cumulative Transportation and Traffic Impacts

Cumulative Mitigation Measures

4.7 TRANSPORTATION AND TRAFFIC

The proposed amended regulation will require facilities to collectively lower their emissions, thus improving air quality in the long term in order to meet the project's objectives. However, the installation of air pollution control equipment as a result of implementing the proposed project could potentially result in transportation and traffic impacts. The transportation and traffic analysis in this PEA identifies the net effect of transportation and traffic impacts from implementing the proposed project.

4.7.1 Introduction

As previously summarized in Table 4.0-2, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment for the top NOx emission equipment/source categories. The equipment/source categories are divided into two sectors: refinery and non-refinery. There are nine facilities in the refinery sector and 11 facilities in the non-refinery sector. For both sectors, individual facilities were evaluated to determine the number and type of NOx control devices that may be installed as a result of implementing the proposed project. Reducing NOx emissions from the affected facilities will provide an air quality benefit in the near- and long-term. Direct air quality impacts from the proposed project are expected to result in a reduction of NOx at the affected facilities, which will provide air quality and human health benefits to the public. However, installing new or modifying existing air pollution control equipment is expected to have potentially adverse transportation and traffic impacts.

The environmental analysis assumes that installation of NOx control technologies for the affected sources will reduce NOx emissions overall, but construction activities associated with both the installation of new control devices and the modification of existing control devices will create adverse transportation and traffic impacts. A project generates adverse transportation and traffic impacts both during the period of its construction and through ongoing daily operations. During installation or modification of add-on air pollution control devices, transportation and traffic impacts may be generated by delivering onsite construction equipment and by offsite vehicles used for worker commuting. After construction activities are completed, transportation and traffic impacts may be generated by maintenance activities associated with the operation of the add-on air pollution control devices such as offsite vehicles used for delivering fresh materials needed for operations (e.g., chemicals, fresh catalyst, etc.) and hauling away solid waste for disposal or recycling (e.g., spent catalyst). The analysis of these impacts can be found in Section 4.7.3. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse transportation and traffic impacts. Refer to Appendix E for the calculations used to estimate secondary construction- and operational-related transportation and traffic impacts.

4.7.2 Significance Criteria

Impacts on transportation and traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- The project conflicts with applicable policies, plans or programs establishing measures of effectiveness, thereby decreasing the performance or safety of any mode of transportation.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

4.7.3 Potential Transportation and Traffic Impacts and Mitigation Measures

Table 4.7-1 summarizes the estimated number of NOx emission control devices per sector and per equipment/source category. The different types of control devices include Selective Catalytic Reduction (SCR), a proprietary Low Temperature Oxidation technology (LoTOx^{TM}) with or without a Wet Gas Scrubber (WGS), and catalyst impregnated filters with a Dry Gas Scrubber (UltraCat DGS). In total, the proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx^{TM} with WGSs, one LoTOx^{TM} without WGS, and three UltraCat DGSs.

Table 4.7-1

Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	2 SCRs 2 LoTOx^{TM} with WGSs* 1 LoTOx^{TM} without WGS
Refinery	Refinery Process Heaters and Boilers	8	74 SCRs^
Refinery	Refinery Gas Turbines	5	7 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	5	5 LoTOx^{TM} with WGSs 1 SCR
Refinery	Petroleum Coke Calciner	1	1 LoTOx^{TM} with WGS or 1 UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	1	2 SCRs or 1 UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	7	13 SCRs and 1 SCR replacement
		TOTAL	**114 to 117 SCRs** **7 to 8 LoTOx^{TM} with WGSs** **1 LoTOx^{TM} without WGS** **3 UltraCat DGSs**

* Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs.

^ Since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74.

4.7.3.1 Construction Analysis

Construction activities resulting from implementing the proposed project may generate a temporary increase in traffic in the areas of each affected facility associated with construction workers, construction equipment, and the delivery of construction materials. However, the proposed project is not expected to cause a significant increase in traffic relative to the existing traffic load and capacity of the street systems surrounding the affected facilities. Also, the proposed project is not expected to exceed, either individually or cumulatively, the current LOS of the areas surrounding the affected facilities during construction as explained in the following discussion.

Table 4.7-2 summarizes the number of construction workers and delivery/haul trips that may be needed to install the various NOx control equipment during construction for both the refinery and non-refinery sectors.

Table 4.7-2
Estimated Number of Worker Trips and Delivery/Haul Trips Needed During Construction of NOx Control Devices in a Peak Day

Sector	Equipment/Source Category	Type of NOx Control Technology	Peak Daily Construction Workers Trips Needed Per NOx Control	Peak Daily Delivery/ Haul Trips Needed
Refinery	FCCUs	1. SCR 2. LoTOx™ with WGS 3. LoTOx™ without WGS	1. 140 2. 175 3. 20	1. 10 2. 10 3. 10
Refinery	Refinery Process Heaters and Boilers	SCR	20	10
Refinery	Refinery Gas Turbines	SCR	20	10
Refinery	SRU/TGUs	1. LoTOx™ with WGS 2. SCR	1. 175 2. 140	1. 10 2. 10
Refinery	Petroleum Coke Calciner	1. LoTOx™ with WGS 2. UltraCat DGS	1. 175 2. 175	1. 10 2. 10
Non-Refinery	Container Glass Melting Furnaces	1. SCR 2. UltraCat DGS	1. 18 2. 175	1. 5 2. 10
Non-Refinery	Sodium Silicate Furnaces	1. SCR 2. UltraCat DGS	1. 18 2. 175	1. 5 2. 10
Non-Refinery	Metal Heat Treating Furnaces	SCR	18	5
Non-Refinery	ICEs (Non-Refinery/Non-Power Plant)	SCRs	18	5
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	SCR	18	5

There are multiple source categories with multiple approaches to reducing NOx at the refinery facilities. With so many possibilities or permutations of how operators of the refinery could achieve actual NOx reductions, there is no way to predict what each facility operator will actually do. For this reason, the analysis illustrates the worst-case effects of applying the various NOx control technologies to each affected facility.

From a construction point of view, the installation of a NOx control technology at a facility is a rather complex process. For example, if a facility operator chooses to install NOx control equipment, time will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential control equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and lining up contractors and workers. The amount of lead time can vary from six months (e.g., for a SCR for refinery/boiler heater or gas turbine) to up to 18 months for a scrubber (either a WGS or DGS).

Then to physically build the equipment, an additional six to 18 months would be needed. For example, six months would be needed to construct one SCR for one refinery boiler/ heater or gas turbine, 12 months would be needed to construct a SCR for a FCCU, and up to 18 months would be needed to construct a scrubber (either a WGS or DGS) for a FCCU or SRU/TGU. Where the new equipment will be sited will determine if any demolition activities would be required. For this analysis, scrubber installation would have the most impacts relative to the number of construction workers and delivery/haul trips needed. Thus, to be conservative, to construct one WGS, one month of demolition activities is assumed to occur at each affected facility and an additional 17 months is assumed for site preparation, assembly and installation of the unit and ancillary support equipment, preparation of the affected unit for a turnaround/shutdown, and tying-in the new scrubber to the affected equipment. As a practical matter, construction activities that are anticipated to occur as a result of implementing the proposed project would likely occur prior to a scheduled maintenance (e.g., turnaround) of the affected unit.

Typically construction projects have staggered construction schedules which take into account design and engineering, ordering, purchasing and delivery of equipment, permitting and environmental review, the availability of construction crews, budgeting, and any other construction projects on site. However, due to wide range of construction time necessary to build the various types of NOx control equipment, the construction activities at other affected facilities could overlap. However, because of widely varying turnaround schedules of affected equipment within any given facility and based on past construction projects involving major construction equipment where the SCAQMD was the lead agency, the air quality analysis in Subchapter 4.2 of this PEA includes a conservative assumption that all of the refineries will have overlapping construction activities occurring in one year. However, since having all facilities construct all NOx controls within the first year is unlikely, for demonstrative purposes, the air quality analysis also includes an analysis of the overlapping construction impacts spread out over a five- and seven-year period.

However, for conducting a worst-case transportation and traffic analysis, the significance criteria is on a per facility basis because the facilities are not located close enough together to have large amounts of overlapping traffic. Of the 20 facilities that may install NOx control equipment as a result of the proposed project, Refinery 5 represents the worst-case for construction activities because it has the most equipment/source categories identified as potential candidates for installing NOx control equipment. Based on conversations with operators at Refinery 5, from a construction worker point of view, the turnaround schedule for the FCCU and SRU/TGUs could overlap but both SRU/TGUs would not be shut-down at the same time. Thus, the analysis assumes that construction overlap of the two SRU/TGUs prior to when the turnarounds would not be expected to occur. For the purpose of conducting a worst-case analysis, construction of one SCR for the FCCU and construction for one LoTOx^{TM} system with one WGS scrubber is assumed to overlap. Further, Refinery 5 is projected to retrofit three gas turbines and 12 boilers and heaters with SCR, for a total of 15 units. Peak SCR construction for refinery boilers, heaters and gas turbines was based on a one-third overlap or five SCRs being installed at one time.

Table 4.7-3 summarizes the number of construction workers and delivery/haul trips that may be needed to install the various NOx control equipment during construction at Refinery 5 on a peak day.

Table 4.7-3

Estimated Number of Worker Trips and Delivery/Haul Trips Needed During Construction of NOx Control Devices in a Peak Day For Refinery 5

Affected Equipment/Source Category at Refinery 5	Type of NOx Control Technology	Overlap of Construction for NOx Controls on a Peak Day	Peak Daily Construction Workers Trips Needed Per NOx Control	Peak Daily Delivery/ Haul Trips Needed
1 FCCU	1 SCR	1 SCR	140	10
2 SRU/TGUs	2 LoTOx™ with WGS	1 LoTOx™ with 1 WGS	175	10
1 SRU/TGU	1 SCR	0	0	0
3 Gas Turbines*	3 SCR	1	20	10
12 Boilers/Heaters *	12 SCRs	4	80	40
		TOTAL	**415**	**70**
		Significance Threshold?	700	350
		Significant?	**NO**	**NO**

* While Refinery 5 could install a total of 15 new SCRs for their boilers/heaters/gas turbines, peak construction is based on a 1/3rd overlap of 5 SCRs at one time.

As shown in Table 4.7-3, the peak daily increase in construction workers at a peak facility (Refinery 5) is 415 the peak daily increase in delivery and haul trips utilizing a heavy-duty is 70. Both of these values are less than their respective significance thresholds.

Even if all 415 construction workers drive alone (which represents an average vehicle ridership equal to 1.0), it is unlikely that these vehicle trips would substantially affect the LOS at any intersection because the trips will be somewhat dispersed over a large area. Therefore, the peak daily work force is not expected to significantly increase as a result of the proposed project.

Therefore, the peak daily work force during construction is not expected to significantly increase as a result of the proposed project. Further, the peak daily number of heavy-duty truck trips during construction is also not expected to significantly increase as a result of the proposed project.

Further, the conclusion of no significant transportation impacts based on the workforce is consistent with the transportation analyses in the CEQA documents prepared for six refineries in accordance with the CARB Phase III Reformulated Gasoline requirements[1]. Specifically, the number of construction workers for each of the six projects ranged from approximately 200 to 700 daily construction worker trips and each of these projects was concluded to have no significant transportation impacts.

4.7.3.3 Mitigation of Transportation and Traffic Impacts During Construction

Less than significant adverse impacts associated with transportation and traffic impacts are expected from the proposed project during construction, so no mitigation measures during construction are required.

4.7.3.6 Remaining Construction Transportation and Traffic Impacts After Mitigation

The transportation and traffic analysis concluded that potential transportation and traffic impacts during construction would be adverse, but less than significant, so mitigation measures during construction are not required. Thus, transportation and traffic impacts during construction remain less than significant.

4.7.3.4 Operation Analysis

Non-Refinery Facilities

The following activities may be sources of transportation and traffic impacts during operation of NOx control equipment at 11 non-refinery facilities: 1) vehicle trips via heavy-duty truck for periodic ammonia/urea deliveries for each SCR and Ultracat filtration unit installed; 2) vehicle trips via heavy-duty truck for periodic deliveries of hydrated lime, catalyst, and replacement filters as well as solid waste hauling of spent filters for each Ultracat system installed. In addition to heavy-duty truck trips, the analysis assumes that one medium-duty round-trip for control system maintenance personnel may be needed for each of the 11 non-refinery facilities. A summary of these heavy-duty truck trips are presented in Table 4.7-4.

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[1]
1. Final EIR for Chevron El Segundo CARB Phase 3 Clean Fuels Project, certified November 30, 2001. http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/chevron/final/chev_f.html
2. Final Environmental Impact Report for: Proposed Ultramar Wilmington Refinery - CARB Phase 3 Project, certified December 19, 2001 http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/ultramar/final/ultEIR_f.html
3. Final Environmental Impact Report for: Proposed Equilon Enterprises LLC CARB Phase 3 Reformulated Gasoline Project, certified October 15, 2001. http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/equilon/final/equEIR_f.html
4. Final Environmental Impact Report for: Mobil CARB Phase 3 Reformulated Gasoline Project, certified October 12, 2001. http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/mobil/final/mobil_f.html
5. Final Environmental Impact Report for: ARCO CARB Phase 3/MTBE Phase-out Project, certified May 15, 2001. http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/arco/finalEIR/arcoFEIR.html
6. Final Environmental Impact Report for: Proposed Tosco Los Angeles Refinery - Phase 3 Reformulated Fuels Project, certified April 5, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/tosco_rfp/final/toscoEIR_f.html)

Table 4.7-4

Operational Truck Trips at 11 Non-Refinery Facilities

Truck Trips	NH3/Urea Delivery Trips[1]	Hydrated Lime Delivery Trips [1,2]	Solid Waste Haul Trips[1]	Filter Waste Haul Trips[1]	Catalyst Delivery Trips[3]	Control System Maintenance Trips[4]	Total Trips
Annual	437	5	11	1	11	11	476
Peak Daily	11	1	1	1	11	1	26

[1] Peak daily trips assumed one ammonia/urea delivery occurs at each non-refinery facility and adsorbent, solid waste and filter waste haul trips occurs on the same day.
[2] Adsorbent, solid waste and filter waste based on vendor estimates for SOx portion of Ultracat system.
[3] Only five catalyst delivery trips are expected because catalysts are replaced every two to three years.
[4] A medium-duty truck is assumed for control system maintenance.

Refinery Facilities

The following activities may be sources of transportation and traffic impacts during operation of NOx control equipment at 9 refinery facilities: 1) vehicle trips via heavy-duty truck for periodic deliveries of ammonia for each SCR installed, NaOH for two LoTOx^{TM} WGSs installed, soda ash for two LoTOx^{TM} WGSs installed, hydrated lime for the Ultracat DGS installed, and oxygen for every LoTOx^{TM} unit installed; 2) vehicle trips via heavy-duty truck for periodic deliveries of catalyst and replacement filters as well as solid waste hauling of spent filters for each SCR unit installed; and 3) via heavy-duty truck hauling solid waste generated by each scrubber (WGS and DGS) installed. A summary of these heavy-duty truck trips are presented in Table 4.7-5.

Table 4.7-5

Heavy-Duty Operational Truck Trips at 9 Refinery Facilities

	Number of Heavy-Duty Truck Trips								
	NH3[1]	NaOH[1]	Hydrated Lime[1]	Soda Ash[1]	Oxygen [1]	Fresh Catalyst[2]	Solid Waste[1]	Spent Catalyst[2]	TOTAL
Annual	498	56	26	21	44	49	96	49	839
Peak Daily	17	3	1	4	1	16	7	16	65

[1] Peak daily trips assumed one heavy-duty truck trip occurs at each refinery facility for each chemical delivery or waste/spent catalyst haul trip.
[2] SCR fresh catalyst delivery trips are expected when the SCR is first built and then replaced every five years. Similarly, spent catalyst waste is also generated every five years.

As shown in Table 4.7-6, the amount of truck trips associated with the proposed project if all 20 facilities install NOx control equipment is 91 round trips in a peak day and 1,315 in one year.

Table 4.7-6
Operational Truck Trips at 20 Affected Facilities

Sector	Peak Daily Truck Trips	Annual Truck Trips
9 Refineries	65	839
11 Non-Refineries	26	476
TOTAL	**91**	**1,315**

Since the increase in transport truck traffic to and/or from each of the 20 affected facilities and from all 20 affected facilities combined is not greater than 350 truck round trips per day, less than significant transportation impacts are expected from implementation of the proposed project during operation. Further, taking into consideration the “worst-case” delivery and hauling transportation schedule, delivery and hauling trips associated with the proposed project are not expected to exceed, either individually or cumulatively, the current LOS of the areas surrounding the affected facilities during operations. Thus, the projected increase of traffic due to operational activities is expected to be minimal and thus, the traffic impacts are expected to be less than significant for the proposed project.

4.7.3.5 Mitigation of Transportation and Traffic Impacts During Operation

Less than significant adverse impacts associated with transportation and traffic impacts are expected from the proposed project during operation, so no mitigation measures are required.

4.7.3.6 Remaining Operational Transportation and Traffic Impacts After Mitigation

The transportation and traffic analysis concluded that potential transportation and traffic impacts during operation would be adverse, but less than significant, so mitigation measures are not required. Thus, transportation and traffic impacts during operation remain less than significant.

4.7.4 Cumulative Transportation and Traffic Impacts

Because the project-specific transportation and traffic impacts do not exceed any applicable significance thresholds during construction and operation, they are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, do not generate significant adverse cumulative transportation and traffic impacts.

4.7.5 Cumulative Mitigation Measures

Because the project-specific transportation and traffic impacts during construction and operation are not considered to be cumulatively considerable, no cumulative mitigation measures are required.

SUBCHAPTER 4.8

OTHER CEQA TOPICS

Potential Environmental Impacts Found Not to be Significant

Significant Environmental Effects Which Cannot Be Avoided

Potential Growth-Inducing Impacts

Relationship Between Short-Term Uses and Long-Term Productivity

4.8 OTHER CEQA TOPICS

4.8.1 Potential Environmental Impacts Found Not to be Significant

While all the environmental topics required to be analyzed under CEQA were reviewed to determine if the proposed project would create significant impacts, the screening analysis in the NOP/IS concluded that the following environmental areas would not be significantly adversely affected by the proposed project: agriculture and forestry resources, biological resources, cultural resources, geology and soils, land use and planning, mineral resources, noise, population and housing, public services, and recreation. Eight comment letters were received from the public relative to the NOP/IS. The comment letters and responses to individual comments are included in Appendix G of this document. No comment letters were received that identified other potentially significant adverse impacts from the proposed project.

In addition, subsequent to the release of the NOP/IS, the requirements of California Assembly Bill (AB 52) went into effect on July 1, 2015. AB 52 is promulgated in Public Resources Code §21080.3.1 (d) and requires a formal notification to all California Native American Tribes about lead agency projects that would require the preparation of a CEQA document. While the Office of Planning and Rule (OPR) has until July 1, 2016 to finalize the implementation guidance for this requirement, the SCAQMD is required to comply with AB 52 in the interim.

The Native American Heritage Commission (NAHC) has provided interim guidance to SCAQMD staff recommending that notifications to California Native American Tribes should occur at the same time the SCAQMD releases a CEQA document for public review and comment. The SCAQMD currently follows the State Clearinghouse (SCH) procedures for distributing all CEQA documents to reviewing agencies and the NAHC was specifically designated as a reviewing agency at the time the NOP/IS was released for public review and comment. Of the eight comment letters that were received relative to the NOP/IS, none were from the NAHC. In addition to following the SCH procedures for soliciting agency review of CEQA documents, SCAQMD staff also sent a copy of the NOP for this project to an interested party contact list, which included over 100 contacts for Native American Tribes. Again, no comment letters from any contacts on the Native American Tribes list were received relative to the NOP/IS.

Since the NOP/IS was released for public review and comment prior to July 1, 2015, the Cultural Resources checklist, significance criteria, and discussion that was originally published in the NOP/IS did not reflect the requirements of AB 52. As such, the Cultural Resources checklist, significance criteria, and discussion have been updated in this PEA to specifically address Native American cultural resources in accordance with the requirements of AB 52. However, the conclusion of "No Impact" for all questions under this topic area remains unchanged. Further, SCAQMD staff ~~will continue to~~ followed the same procedures for designating the NAHC as a reviewing agency and for notifying all of the Native American Tribes contained in SCAQMD's interested party database as to the availability of the Draft PEA for public review and comment.

The following is a brief discussion of each environmental topic area found not to be significant in the NOP/IS:

Agriculture and Forestry Resources

Land use, including agriculture- and forest-related uses, and other planning considerations are determined by local governments. While implementation of the proposed project may cause air pollution control equipment to be installed and operated on existing equipment to control NOx emissions, these activities will occur at established NOx RECLAIM facilities which are located on previously developed land in primarily industrial areas and are not located in the vicinity of agricultural or forest areas.

Further, no new construction of buildings or other structures is expected that would require conversion of farmland to non-agricultural use or conflict with zoning for agricultural uses or a Williamson Act contract. Further, because the proposed project does not require construction or operation activities within an area designated as forest land, implementation of the proposed project is not expected to conflict with any forest land zoning codes or convert forest land to non-forest uses. Similarly, there is nothing in the proposed project that would affect or conflict with existing land use plans, policies, or regulations or require conversion of farmland to non-agricultural uses or forest land to non-forest uses. Thus, no agricultural land use or planning requirements will be altered by the proposed project.

Finally, in the event the proposed project is implemented, the installation of NOx control equipment will ensure that projected NOx emission reductions will occur and that air quality in the region will improve. Thus, assuring that these air quality improvements occur could provide benefits to agricultural and forest land resources by reducing the adverse oxidation impacts of ozone on plants and animals located in the Basin. Accordingly, these impact issues will not be further analyzed in the ~~Draft~~ Final PEA.

Based upon these considerations, significant agricultural and forestry resources impacts are not expected from implementing the proposed project, and thus, this topic was not further analyzed in the ~~Draft~~ Final PEA. Since no significant agriculture and forestry resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

Biological Resources

The proposed project would only affect units operating at the top NOx emitting facilities in the NOx RECLAIM program. These facilities have locations scattered throughout the District. All of the affected units operating at existing facilities are located primarily in developed industrial areas, which have already been greatly disturbed and paved. These areas currently do not support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found within close proximity to the affected sites within the facilities. Therefore, the proposed project would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely in the SCAQMD's jurisdiction. The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions. A conclusion in the Final Program EIR for the 2012 AQMP was that population growth in the region would have greater adverse effects on plant species and wildlife dispersal or migration corridors in the basin than SCAQMD regulatory activities, (e.g., air quality control measures or regulations). In addition, by reducing air pollutants, biological resources will benefit. Moreover, the current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions.

Further, the proposed project is not envisioned to conflict with local policies or ordinances protecting biological resources or local, regional, or state conservation plans. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Additionally, the proposed project will not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan, and would not create divisions in any existing communities because all activities associated with complying with the proposed project will occur at existing industrial facilities.

Based upon these considerations, significant biological resources impacts are not expected from implementing the proposed project, and thus, this topic was not further analyzed in the ~~Draft~~ Final PEA. Since no significant biological resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

Cultural Resources

Subsequent to release of the NOP/IS, modifications were made to the environmental checklist, significance criteria, and discussion of Cultural Resources impacts in response to the requirements in AB 52 to consider the proposed project's potential effects on Cultural Native American Tribe resources. To facilitate identification of what updates have been made to the environmental checklist, significance criteria, and discussion of Cultural Resources impacts in response to the requirements in AB 52 to consider Cultural Native American Tribe impacts, the Cultural Resources portion of the NOP/IS checklist has been repeated in this PEA. The updates are included as underlined text. However, even with the additional information, the overall conclusion of "No Impact" for this topic area remains unchanged.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
V.	**CULTURAL RESOURCES.** Would the project:				
a)	Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☐	☐	☑
b)	Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☐	☑
c)	Directly or indirectly destroy a unique paleontological resource, site, or feature?	☐	☐	☐	☑
d)	Disturb any human remains, including those interred outside formal cemeteries?	☐	☐	☐	☑
e)	<u>Cause a substantial adverse change in the significance of a tribal cultural resource as defined in Public Resources Code §21074?</u>	☐	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance, <u>or tribal cultural significance</u> to a community or ethnic or social group <u>or a California Native American tribe</u>.
- Unique paleontological resources or objects with cultural value to a California Native American tribe are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

Discussion

V. a) No Impact. There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. Since construction-related activities associated with the implementation of the proposed project are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved, no impacts to historical resources are expected to occur as a result of implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

V. b), c), & d) No Impact. Installing or modifying add-on controls and other associated equipment to comply with the proposed project may require disturbance of previously disturbed areas at the affected existing industrial facilities. However, since construction-related activities are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved, the proposed project is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources. Furthermore, it is envisioned that these areas are already either devoid of significant cultural resources or whose cultural resources have been previously disturbed. Therefore, the proposed project has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. The proposed project is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the District. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

V. e) No Impact. The proposed project is not expected to require physical changes to a site, feature, place, cultural landscape, sacred place or object with cultural value to a California Native American Tribe. Furthermore, the proposed project is not expected to result in a physical change to a resource determined to be eligible for inclusion or listed in the California Register of Historical Resources or included in a local register of historical resources. For these reasons, the proposed project is not expected to cause any substantial adverse change in the significance of a tribal cultural resource as defined in Public Resources Code §21074.

It is important to note that as part of releasing this CEQA document for public review and comment, the SCAQMD also provided a formal notice of the proposed project to all California Native American Tribes (Tribes) that requested to be on the Native American Heritage Commission's (NAHC) notification list per Public Resources Code §21080.3.1 (b)(1). The NAHC notification list provides a 30-day period during which a Tribe may respond to the formal notice, in writing, requesting consultation on the proposed project.

In the event that a Tribe submits a written request for consultation during this 30-day period, the SCAQMD will initiate a consultation with the Tribe within 30 days of receiving the request in accordance with Public Resources Code §21080.3.1 (b). Consultation ends when either: 1) both parties agree to measures to avoid or mitigate a significant effect on a Tribal Cultural Resource and agreed upon mitigation measures shall be recommended for inclusion in the environmental document [see Public Resources Code §21082.3 (a)]; or, 2) either party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached [see Public Resources Code §21080.3.2 (b)(1)-(2) and §21080.3.1 (b)(1)].

Based upon these considerations, significant cultural resources impacts are not expected from implementing the proposed project, and thus, this topic was not further analyzed in the ~~Draft~~ Final PEA. Since no significant cultural resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

Geology and Soils

Since the proposed project would result in construction activities at existing RECLAIM facilities located in developed industrial settings to install or modify NOx control equipment, little site preparation is anticipated that could adversely affect geophysical conditions in the jurisdiction of the SCAQMD. Southern California is an area of known seismic activity. Accordingly, the installation of add-on controls at existing affected facilities to comply with the proposed project is expected to conform to the Uniform Building Code and all other applicable state and local building codes. As part of the issuance of building permits, local jurisdictions are responsible for assuring that the Uniform Building Code is adhered to and can conduct inspections to ensure compliance. The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The basic formulas used for the Uniform Building Code seismic design require determination of the seismic zone and site coefficient, which represents the foundation condition at the site. The Uniform Building Code requirements also consider liquefaction potential and establish stringent requirements for building foundations in areas potentially subject to liquefaction. Thus, the proposed project would not alter the exposure of people or property to geological hazards such as earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structures to the risk of loss, injury, or death involving the rupture of an earthquake fault, seismic ground shaking, ground failure or landslides is not anticipated.

Since add-on controls will likely be installed at existing developed facilities, during construction of the proposed project, a slight possibility exists for temporary erosion resulting from excavating and grading activities, if required. These activities are expected to be minor since the existing facilities are generally flat and have previously been graded and paved. Further, wind erosion is not expected to occur to any appreciable extent, because operators at dust generating sites would be required to comply with the best available control measure (BACM) requirements of SCAQMD Rule 403 – Fugitive Dust. In general, operators must control fugitive dust through a number of soil stabilizing measures such as watering the site, using chemical soil stabilizers, revegetating inactive sites, etc. The proposed project involves the installation or modification of add-on control equipment at existing facilities, so that grading could be required to provide stable foundations. Potential air quality impacts related to grading are addressed elsewhere in this Initial Study (as part of construction air quality impacts). No unstable earth conditions or changes in geologic substructures are expected to result from implementing the proposed project.

Since the proposed project will affect existing facilities, it is expected that the soil types present at the affected facilities will not be made further susceptible to expansion or liquefaction. Furthermore, subsidence is not anticipated to be a problem since only minor excavation, grading, or filling activities are expected occur at affected facilities. Additionally, the affected areas are not envisioned to be prone to new landslide impacts or have unique geologic features since the affected equipment units are located at existing facilities in industrial areas.

Since the proposed project will affect equipment units at existing facilities located in industrial zones, it is expected that people or property will not be exposed to new impacts related to expansive soils or soils incapable of supporting water disposal. Further, typically each affected facility has some degree of existing wastewater treatment systems that will continue to be used and are expected to be unaffected by the proposed project. Sewer systems are available to handle wastewater produced and treated by each affected facility. Each existing facility affected by the proposed project does not require installation of septic tanks or alternative wastewater disposal systems. As a result, the proposed project will not require facility operators to utilize septic systems or alternative wastewater disposal systems. Thus, implementation of the proposed project will not adversely affect soils associated with a septic system or alternative wastewater disposal system.

Based upon these considerations, significant geology and soils impacts are not expected from the implementation of the proposed project, and thus, this topic was not further analyzed in the ~~Draft~~ Final PEA. Since no significant geology and soils impacts were identified for any of the issues, no mitigation measures are necessary or required.

Land Use and Planning

The proposed project does not require the construction of new facilities, but any physical effects that will result from the proposed project, will occur at existing RECLAIM facilities located in heavy industrial areas and would not be expected to go beyond existing boundaries. Thus, implementing the proposed project will not result in physically dividing any established communities.

Further, there are no provisions in the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Further, the proposed project would be consistent with the typical industrial zoning of the affected facilities. Typically, all proposed construction activities are expected to occur within the confines of the existing facilities. The proposed project would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Finally, no new development or alterations to existing land designations will occur as a result of the implementation of the proposed project. Therefore, present or planned land uses in the region will not be affected as a result of implementing the proposed project.

Based upon these considerations, significant land use planning impacts are not expected from the implementation of the proposed project, and thus, will not be further analyzed in the ~~Draft~~ Final PEA. Further, since no significant impacts were identified for any of these issues, no mitigation measures are necessary or required.

Mineral Resources

There are no provisions in the proposed project that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Based upon these considerations, significant mineral resource impacts are not expected from the implementation of the proposed project, and thus, will not be further analyzed in the

~~Draft~~ Final PEA. Since no significant mineral resource impacts were identified for any of these issues, no mitigation measures are necessary or required.

Noise

Modifications or changes associated with the implementation of the proposed project will take place at existing RECLAIM facilities that are typically located in heavy industrial settings. The existing noise environment at each of the affected facilities is typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises. Construction activities associated with implementing the proposed project may generate some noise associated with the use of construction equipment and construction-related traffic. However, noise from the proposed project is not expected to produce noise in excess of current operations at each of the existing facilities. If NOx control devices are installed or existing devices are modified, the operations phase of the proposed project may add new sources of noise to each affected facility. However, control devices are not typically equipment that generate substantial amounts of noise. Nonetheless, for any noise that may be generated by the control devices, it is expected that each facility affected will comply with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA (Cal/OSHA) have established noise standards to protect worker health. These potential noise increases are expected within the allowable noise levels established by the local noise ordinances for industrial areas, and thus are expected to be less than significant. Therefore, less than significant noise impacts are expected to result from the operation of the proposed project.

Though some of the facilities affected by the proposed project are located at sites within an airport land use plan, or within two miles of a public airport, the addition of new or modification of existing NOx control equipment would not expose people residing or working in the project area to the same degree of excessive noise levels associated with airplanes. All noise producing equipment must comply with local noise ordinances and applicable OSHA or Cal/OSHA workplace noise reduction requirements. Therefore, less than significant noise impacts are expected to occur at sites located within an airport land use plan, or within two miles of a public airport.

Based upon these considerations, significant noise impacts are not expected from the implementation of the proposed project and will not be further analyzed in the ~~Draft~~ Final PEA. Further, since no significant impacts were identified for any of these issues, no mitigation measures are necessary or required.

Population and Housing

The construction activities associated with the proposed project at each affected facility are not expected to involve the relocation of individuals, require new housing or commercial facilities, or change the distribution of the population. The reason for this conclusion is that operators of affected facilities who need to perform any construction activities to comply with the proposed project can draw from the large existing labor pool in the local southern California area. Further, it is not expected that the installation of new or the modification of existing NOx control equipment will require new employees during operation of the equipment. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing the proposed project. As a result, the proposed project is not anticipated to generate any significant adverse effects, either direct or indirect, on population growth in the district or population distribution.

Because the proposed project includes modifications and/or changes at existing facilities located in heavy industrial settings, the proposed project is not expected to result in the creation of any industry that would affect population growth, directly or indirectly induce the construction of single- or multiple-family units, or require the displacement of people or housing elsewhere in the district.

Based upon these considerations, significant population and housing impacts are not expected from the implementation of the proposed project, and thus, will not be further evaluated in the ~~Draft~~ Final PEA. Since no significant population and housing impacts were identified for any of these issues, no mitigation measures are necessary or required.

Public Services

Implementation of the proposed project is expected to cause facility operators to install new or modify existing NOx control devices, all the while continuing current operations at existing affected facilities. The proposed project may result in a greater demand for catalyst, scrubbing agents and other chemicals, which will need to be transported to the affected facilities to support the function of NOx control equipment and stored onsite prior to use. As first responders to emergency situations, police and fire departments may assist local hazmat teams with containing hazardous materials, putting out fires, and controlling crowds to reduce public exposure to releases of hazardous materials. In addition, emergency or rescue vehicles operated by local, state, and federal law enforcement agencies, police and sheriff departments, fire departments, hospitals, medical or paramedic facilities, that are used for responding to situations where potential threats to life or property exist, including, but not limited to fire, ambulance calls, or life-saving calls, may be needed in the event of an accidental release or other emergency. While the specific nature or degree of such impacts is currently unknown, the affected facilities have existing emergency response plans so any changes to those plans would not be expected to dramatically alter how emergency personnel would respond to an accidental release or other emergency. In addition, due the low probability and unpredictable nature of accidental releases, the proposed project is not expected to increase the need or demand for additional public services (e.g., fire and police departments and related emergency services, et cetera) above current levels.

As noted in the previous "Population and Housing" discussion, the proposed project is not expected to induce population growth in any way because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any construction activities that may be necessary at affected facilities and operation of new or modified NOx control equipment is not expected to require additional employees. Therefore, there will be no increase in local population and thus no impacts are expected to local schools or parks.

The proposed project is expected to result in the use of new or modified add-on control equipment for NOx control. Besides permitting the equipment or altering permit conditions by the SCAQMD, there is no need for other types of government services. The proposed project would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population and, therefore, no need for physically altered government facilities.

Based upon these considerations, significant public services impacts are not expected from the implementation of the proposed project and will not be further evaluated in the ~~Draft~~ Final PEA. Since no significant public services impacts were identified for any of these issues, no mitigation measures are necessary or required.

Recreation

As discussed earlier under the topic of "Population and Housing," there are no provisions in the proposed project that would affect or increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or the expansion of existing recreational facilities that might have an adverse physical effects on the environment because the proposed project will not directly or indirectly increase or redistribute population. Based upon these considerations, including the conclusion of "no impact" for the topic of "Population and Housing," significant recreation impacts are not expected from implementing the proposed project, and thus, this topic was not further analyzed in the ~~Draft~~ Final PEA. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

4.8.2 Significant Environmental Effects Which Cannot Be Avoided

CEQA Guidelines §15126 (c) requires an environmental analysis to consider "any significant irreversible environmental changes which would be involved if the proposed action should be implemented." This PEA identified the topics of air quality and GHGs and water demand (under the topic of hydrology and water quality) as the environmental topic areas potentially adversely affected by the proposed project. The NOP/IS also identified the topics of aesthetics, energy, hazards and hazardous materials, solid and hazardous waste, and transportation and traffic as having potentially significant adverse impacts, but after further analysis, these topics were determined to have less than significant impacts. Significant adverse impacts from GHGs generated from both construction and operation activities may be considered irreversible. Facility operators that install new NOx controls or modify existing units are likely to operate these systems for the lifetime of the equipment.

4.8.3 Potential Growth-Inducing Impacts

CEQA Guidelines §15126 (d) requires an environmental analysis to consider the "growth-inducing impact of the proposed action." CEQA defines growth-inducing impacts as those impacts of a proposed project that "could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment. Included in this are projects, which would remove obstacles to population growth." [CEQA Guidelines §15126.2 (d)]

To address this issue, potential growth-inducing effects are examined through the following considerations:

- Facilitation of economic effects that could result in other activities that could significantly affect the environment;
- Expansion requirements for one or more public services to maintain desired levels of service as a result of the proposed project;
- Removal of obstacles to growth through the construction or extension of major infrastructure facilities that do not presently exist in the project area or through changes in existing regulations pertaining to land development;
- Adding development or encroachment into open space; and/or
- Setting a precedent that could encourage and facilitate other activities that could significantly affect the environment.

4.8.3.1 Economic and Population Growth, and Related Public Services

A project would be considered to directly induce growth if it would directly foster economic or population growth or the construction of new housing in the surrounding environment (e.g., if it would remove an obstacle to growth by expanding existing infrastructure such as new roads or wastewater treatment plants). The proposed project would not remove barriers to population growth, as it involves no changes to a General Plan, zoning ordinance, or a related land use policy.

Further, the proposed project does not include policies that would encourage the development of new housing or population-generating uses or infrastructure that would directly encourage such uses. The proposed project may indirectly increase the efficiency of the region's urban form through encouraging more air quality efficient development patterns in the form of NOx reductions. The proposed project does not change jurisdictional authority or responsibility concerning land use or property issues. Land use authority falls solely under the purview of the local governments. The SCAQMD is specifically excluded from infringing on existing city or county land use authority (California Health and Safety Code §40414). Therefore, the proposed project would not directly trigger new residential development in the area.

The proposed project may result in construction activities associated with installing new or modifying existing air pollution control equipment to achieve NOx reductions. However, the proposed project would not directly or indirectly stimulate substantial population growth, remove obstacles to population growth, or necessitate the construction of new community facilities that would lead to additional growth in the Basin. It is expected that construction workers will be largely drawn from the existing workforce pool in southern California. Considering the existing labor force of about 8.5 million in the region and current unemployment rate of about six percent, it is expected that a sufficient number of workers are available locally and that few or no workers would relocate for construction jobs potentially created by the proposed project as construction activities would be spread over a period from 2015 to 2022[1]. Further, the proposed project would not be expected to result in an increase in local population, housing, or associated public services (e.g., fire, police, schools, recreation, and library facilities) since no increase in population or the permanent number of workers is expected. Likewise, the proposed project would not create new demand for secondary services, including regional or specialty retail, restaurant or food delivery, recreation, or entertainment uses. As such, the proposed project would not foster economic or population growth in the surrounding area in a manner that would be growth-inducing.

Thus, implementing the proposed project will not, by itself, have any direct or indirect growth-inducing impacts on businesses in the SCAQMD's jurisdiction because it is not expected to foster economic or population growth or the construction of additional housing and primarily affects existing facilities.

4.8.3.2 Removal of Obstacles to Growth

The facilities that may be affected by the proposed project are located within an existing urbanized area. The proposed project would not employ activities or uses that would result in growth inducement, such as the development of new infrastructure (e.g., new roadway access or utilities) that would directly or indirectly cause the growth of new populations, communities, or currently undeveloped areas. The proposed project would require additional energy (electricity, diesel, gasoline, and natural gas) to implement but the increased energy requirements are expected to be within those projected for existing population growth of the region. While construction and operation activities that may occur as a result of the proposed project will require trips associated with construction workers, delivery of supplies and haul trips, the analysis in Subchapter 4.7 for Transportation and Traffic concluded that the trips will occur via existing roadways and transportation corridors. Thus, the proposed project is not expected to require the development of new roads or freeways. Likewise, the proposed project would not result in an expansion of existing public service facilities (e.g., police, fire, libraries, and schools) or the development of public service facilities that do not already exist.

4.8.3.3 Development or Encroachments into Open Space

Development can be considered growth-inducing when it is not contiguous to existing urban development and introduces development into open space areas. The proposed project is situated within the existing South Coast Air Basin, which is urbanized. The areas of the Basin where construction activities may occur would be at existing stationary sources and the associated trips would occur along existing transportation corridors. Stationary sources are generally located within commercial and industrial (urbanized) areas. Any related construction activities would be expected to be within the confines of the existing facilities and would not encroach into open space. Therefore, the proposed project would not result in development within or encroachment into an open space area.

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[1] EDD, Labor Market Information Division, California Labor Market Current Status, May/June 2015. http://www.labormarketinfo.edd.ca.gov/county/sbern.html#URLF

4.8.3.4 Precedent Setting Action

Under the NOx RECLAIM program, a BARCT reassessment is required by the California Health and Safety Code ~~§~~§40440 ~~and 39616~~[2] and is needed to capture the advancement in control technology to assure that NOx RECLAIM facilities would achieve emission reductions as expeditiously as possible. In addition, the SCAQMD developed and adopted the 2012 AQMP which established a plan to meet and maintain the state and federal air quality standards. The 2012 AQMP identifies control measures needed to attain the federal 24-hour standard for PM2.5 by 2014 and provides updates on progress towards meeting the 8-hour ozone standard in 2024. In particular, Control Measure CMB-01 is one of the control measures addressed in the 2012 AQMP. This Control Measure reiterates the requirement for a BARCT reassessment for NOx RECLAIM facilities. Finally, since NOx is a precursor of ozone, reducing NOx as a result of implementing the proposed project will help the basin attain the National Ambient Air Quality Standards (NAAQS) for ozone in 2024 and 2032. Therefore, the proposed project is being prepared to comply with state and federal air quality planning regulations and requirements. This project would not result in precedent-setting actions that might cause other significant environmental impacts (other than those evaluated in other sections of this PEA).

4.8.3.5 Conclusion

The proposed project was developed to comply with local, state and federal air quality planning requirements and is not expected to foster economic or population growth or result in the construction of additional housing or other infrastructure, either directly or indirectly, that would further encourage growth. While the proposed project could result in construction projects at existing stationary sources, the proposed project would not be considered growth-inducing, because it would not result in an increase in production of resources or cause a progression of growth that could significantly affect the environment either individually or cumulatively.

4.8.4 Relationship Between Short-Term Uses and Long-Term Productivity

An important consideration when analyzing the effects of a proposed project is whether it will result in short-term environmental benefits to the detriment of achieving long-term goals or maximizing productivity of these resources. Implementing the proposed project is not expected to achieve short-term goals at the expense of long-term environmental productivity or goal achievement. The purpose of the proposed project is to achieve NOx reductions via a BARCT reassessment of NOx RECLAIM facilities in order to achieve emission reductions as expeditiously as possible and comply with local, state and federal air quality planning requirements. By achieving additional reductions in NOx, an ozone and PM2.5 precursor, the proposed project will help attain federal and state air quality standards which are expected to enhance short and long-term environmental productivity in the region.

[2] The reference to Health and Safety Code §39616 has been deleted because it does not require a BARCT analysis. The RECLAIM program proposed here satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so.

Implementing the proposed project does not narrow the range of beneficial uses of the environment. Of the potential environmental impacts discussed in Chapter 4, only those related to air quality and GHG impacts associated with construction and operation activities and water demand (under the topic of hydrology and water quality) are considered potentially significant. Implementation of the recommended mitigation measures will ensure such impacts are mitigated to the greatest degree feasible.

CHAPTER 5

ALTERNATIVES

Introduction

Methodology for Developing Project Alternatives

Description of Alternatives to the Proposed Project

Alternatives Analysis

Comparison of the Alternatives to the Proposed Project

Alternatives Rejected as Infeasible

Lowest Toxic and Environmentally Superior Alternative

Conclusion

5.0 INTRODUCTION

This ~~Draft~~ Final PEA provides a discussion of alternatives to the proposed project as required by CEQA. Pursuant to the CEQA Guidelines, alternatives should include realistic measures to attain the basic objectives of the proposed project but would avoid or substantially lessen any of the significant effects of the project, and provide a means for evaluating the comparative merits of each alternative (CEQA Guidelines §15126.6 (a)). A "No Project" alternative must also be evaluated. In addition, though the range of alternatives must be sufficient to permit a reasoned choice, they need not include every conceivable project alternative (CEQA Guidelines §15126.6 (a)). The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. SCAQMD Rule 110 (the rule which implements the SCAQMD's certified regulatory program) does not impose any greater requirements for a discussion of project alternatives in a program environmental assessment than is required for an EIR under CEQA.

5.1 METHODOLOGY FOR DEVELOPING PROJECT ALTERNATIVES

The alternatives typically included in CEQA documents for proposed SCAQMD rules, regulations, or plans are developed by breaking down the project into distinct components (e.g., emission limits, compliance dates, applicability, exemptions, pollutant control strategies, etc.) and varying the specifics of one or more of the components. Different compliance approaches that generally achieve the objectives of the project may also be considered as project alternatives.

Alternatives to the proposed project were crafted by varying how the NOx RTC shave would be applied to the NOx RECLAIM facilities and RTC investors. The initial analysis of the proposed project in the NOP/IS determined that, of the amendments proposed, only the components that pertain to the lowered BARCT NOx emission factors could entail physical modifications to the affected equipment and that these physical modifications could create potential adverse significant impacts. As such, in addition to the no project alternative, three alternatives were developed by identifying and modifying major components of the proposed project. Specifically, the primary components of the proposed alternatives that have been modified are the source categories that may be affected, and the manner in which compliance with the proposed lowered BARCT NOx emission factors may be achieved. In addition, in response to comments made by industry, a fifth alternative, with parameters suggested by industry, is also included.

Typically, the existing setting is established at the time the NOP/IS is circulated for public review, which was December 2014. This baseline is used for all environmental topics analyzed in this ~~Draft~~ Final PEA. However, CEQA Guidelines §15125 (a) recognizes that a baseline may be established at times other than when the NOP/IS is circulated to the public by stating (emphasis added), "This environmental setting ***will normally*** constitute the baseline physical conditions by which a lead agency determines whether an impact is significant." As explained in Chapter 2, the baseline for the CPCC facility changed subsequent to when the NOP/IS was circulated for public review such that the installation of control technology and the secondary adverse environmental impacts that may be associated with such control technology is no longer a reasonably foreseeable consequence for CPCC under the present circumstances. Thus, this

PEA does not contain an environmental analysis of the control technologies that were originally contemplated in the NOP/IS as BARCT for the CPCC facility. In addition, none of the alternatives described in the chapter contain an environmental analysis of the control technologies specific to the Portland Cement Kilns or the CPCC facility[1].

In addition, since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse environmental impacts for the proposed project.

5.2 DESCRIPTION OF ALTERNATIVES

Five alternatives to the proposed project are summarized in Table 5-1: Alternative 1 (Across the Board), Alternative 2 (Most Stringent), Alternative 3 (Industry Approach), Alternative 4 (No Project), and Alternative 5 (Weighted by BARCT Reduction Contribution for all facilities and investors). The primary components of the proposed alternatives that have been modified are the source categories that may be affected, and the manner in which compliance with the proposed NOx BARCT emission limits may be achieved. Unless otherwise specifically noted, all other components of the project alternatives are identical to the components of the proposed project.

The following subsections provide a brief description of the alternatives.

5.2.1 Alternative 1 – Across the Board Shave of NOx RTCs

Alternative 1 consists of an across the board NOx RTC reduction (shave) of 14 tpd that would affect all NOx RECLAIM facilities and investors. Under Alternative 1, the NOx RTC holdings would be shaved by 53 percent overall. After BARCT is applied, 8.77 ~~8.79~~ tpd of actual NOx reductions from existing emission levels are projected to occur, with an additional 5.23 ~~5.21~~ tpd of NOx RTCs needed to fulfill the shave, post-BARCT. By applying a shave of 53 percent to all facilities, 219 ~~210~~ facilities, which represent the bottom 10 percent of RTC holders, would become potential future buyers of RTCs since the amount of RTC holdings for these facilities would become less than their current actual emissions.

Under Alternative 1, the amount of the proposed NOx RTC shave of 14 tpd is identical to the proposed project. However, the distribution of the shave under Alternative 1 would reduce the NOx RTC holdings differently than the proposed project. Specifically,

[1] Because of CPCC's current permitting status for their Portland cement kilns (e.g., the permits were surrendered), CPCC operators will not be able to retrofit the Portland cement kilns with air pollution control equipment in response to the proposed project without first dealing with the permitting issues for the cement kilns. Thus, the installation of control technology and the secondary adverse environmental impacts that may be associated with such control technology is not a reasonably foreseeable consequence for CPCC under the present circumstances. Further, there are no other facilities in SCAQMD's jurisdiction that operate Portland cement kilns. Thus, this PEA does not contain an environmental analysis of the control technologies that were originally contemplated in the NOP/IS for the CPCC facility.

Alternative 1 would reduce NOx RTC holdings from all 275 NOx RECLAIM facilities and investors by 53 percent overall. The proposed project, however, would reduce NOx RTC holdings by: 1) 66 ~~67~~ percent for 9 refineries and investors (treated as one facility); 2) 49 ~~47~~ percent for 21 EGFs~~30 power plants~~; 3) 49 ~~47~~ percent for 26 non-major facilities; and, 4) zero percent for the remaining 219 ~~210~~ facilities.

The amount of the shave is based on a recent BARCT analysis. For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal heat treating furnaces, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for 30 EGFs~~power plants~~. In order to achieve these new BARCT levels, the likely possibility is that operators of 20 facilities within the affected source categories will reduce actual NOx emissions via physical modifications to a wide variety of equipment by installing new air pollution control equipment or modifying existing air pollution control equipment. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. In particular, the number and type of control equipment that may be installed as a result of the proposed project and the corresponding adverse impacts that were analyzed for the proposed project, the same control equipment and corresponding adverse impacts will also occur under Alternative 1.

5.2.2 Alternative 2 – Most Stringent Shave of NOx RTCs

Alternative 2 consists of the most stringent approach by applying an across the board NOx RTC shave of 15.87 tpd. Alternative 2 would affect all RECLAIM facilities and investors, but without including the 10 percent compliance margin or the BARCT adjustment for refinery equipment. Under Alternative 2, the NOx RTC holdings would be shaved by 60 percent overall. After BARCT is applied, 8.77 ~~8.79~~ tpd of actual NOx reductions are projected to occur, with 7.10 ~~7.08~~ tpd of NOx RTCs needed to fulfill the shave, post-BARCT. By applying a shave of 60 percent to all facilities, 219 ~~210~~ facilities, which represent the bottom 10 percent of RTC holders, would become potential future buyers of RTCs since the amount of RTC holdings for these facilities would become less than their current actual emissions.

Under Alternative 2, the amount of the proposed NOx RTC shave of 15.87 tpd is greater than the 14 tpd NOx RTC shave that is contemplated by the proposed project. In addition, the distribution of the shave under Alternative 2 would reduce the NOx RTC holdings differently than the proposed project. Specifically, Alternative 2 would reduce NOx RTC holdings from all 275 NOx RECLAIM facilities and investors by 60 percent overall. The proposed project, however, would reduce NOx RTC holdings by: 1) 66 ~~67~~ percent for 9 refineries and investors (treated as one facility); 2) 49 ~~47~~ percent for 21 EGFs~~30 power plants~~; 3) 49 ~~47~~ percent for 26 non-major facilities; and, 4) zero percent for the remaining 219 ~~210~~ facilities.

For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal heat treating furnaces, gas turbines and ICEs not located on the OCS. No new

BARCT is proposed for 30 EGFs~~power plants~~. In order to achieve these new BARCT levels, the likely possibility is that operators of 20 facilities with the affected source categories will reduce actual NOx emissions via physical modifications to a wide variety of equipment by installing new air pollution control equipment or modifying existing air pollution control equipment. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. In particular, the number and type of control equipment that may be installed as a result of the proposed project and the corresponding adverse impacts that were analyzed for the proposed project, the same control equipment and corresponding adverse impacts will also occur under Alternative 2.

It is possible that under Alternative 2, facilities could increase their level of control further than what is analyzed for the proposed project to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with possibly additional adverse environmental impacts. However, it would be speculative to predict how many and what type of additional controls would be proposed in order to obtain a compliance margin. For this reason, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project is speculative and cannot be analyzed.

Thus, analysis of Alternative 2 contains the same number and type of control equipment that may be installed as a result of the proposed project and the same corresponding adverse impacts that were analyzed for the proposed project.

5.2.3 Alternative 3 – Industry Approach

Alternative 3, an approach that has been proposed by industry representatives, consists of an across the board NOx RTC shave of 8.77 ~~8.79~~ tpd from total RTC holdings that would affect all RECLAIM facilities and investors. The calculation under Alternative 3 subtracts the base year emissions at the proposed BARCT level from the base year emissions at the previous BARCT level (Year 2000 or 2005). Under Alternative 3, the NOx RTCs held by all RECLAIM facilities and investors would be shaved by 33 percent overall. Since there are currently more NOx RTCs than actual 2011 emissions, it is likely that much of the 8.77 ~~8.79~~ tons per day reduction in RTCs will occur by surrendering excess RTCs rather than installing additional controls. However, some amount of NOx reductions may need to be obtained by installing NOx controls. It is difficult for staff to predict how much NOx emission reductions would be needed from the installation of controls, but it is likely that substantially fewer controls will be installed (and thus, actual NOx reductions achieved) than under the proposed project. By applying a shave of 33 percent to all facilities, 219 ~~210~~ facilities, which represent the bottom 10 percent of RTC holders, would become potential future buyers of RTCs since the amount of RTC holdings for these facilities would become less than their current actual emissions.

Under Alternative 3, the amount of the proposed NOx RTC shave of 8.0 tpd is less than the 14.0 tpd NOx RTC shave that is contemplated by the proposed project. In addition, the distribution of the shave under Alternative 3 would reduce the NOx RTC holdings differently than the proposed project. Specifically, Alternative 3 would reduce NOx RTC holdings from all 275 NOx RECLAIM facilities and investors by 33 percent overall. The proposed project, however, would reduce NOx RTC holdings by: 1) 66 ~~67~~ percent for 9 refineries and investors (treated as one facility); 2) 49 ~~47~~ percent for 21 EGFs~~30 power plants~~; 3) 49 ~~47~~ percent for 26 non-major facilities; and, 4) zero percent for the remaining 219 ~~210~~ facilities.

For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal heat treating furnaces, gas turbines and ICEs not located on the OCS. No new BARCT is proposed for 30 EGFs~~power plants~~. In order to achieve these new BARCT levels, the likely possibility is that operators of 20 facilities with the affected source categories will reduce actual NOx emissions via physical modifications to a wide variety of equipment by installing new air pollution control equipment or modifying existing air pollution control equipment. However, because the proposed NOx RTC shave under Alternative 3 is so much less than the proposed project (e.g., 8.0 tpd vs. 14.0 tpd), it is possible that the entire 8.0 tpd NOx RTC shave could be addressed with unused RTCs without having any facilities modifying their equipment to achieve actual NOx reductions from installing air pollution control equipment. Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

5.2.4 Alternative 4 - No Project

Alternative 4 is the "No Project" approach such that no NOx RTC reductions would be applied to any RECLAIM facility or investor. CEQA requires the specific alternative of No Project to be evaluated. A No Project Alternative consists of what would occur if the proposed project was not approved; in this case, not adopting the proposed project. The net effect of not amending Regulation XX to reduce the available RTCs on the market would be a continuation of the 2005 amendments to the NOx RECLAIM program. This approach is consistent with CEQA Guidelines §15126.6 (e)(3)(B), which states: "If the project is other than a land use or regulatory plan, for example a development project on identifiable property, the "no project" alternative is the circumstance under which the project does not proceed." The discussion in this PEA would compare the environmental effects of the Regulation XX remaining in its existing state against any environmental effects which would occur if the project is approved. If disapproval of the project under consideration would result in predictable actions by others, such as the proposal of some other project, this "no project" consequence should be discussed. In certain instances, the no project alternative means "no build" wherein the existing environmental setting is maintained.

However, where failure to proceed with the project will not result in preservation of existing environmental conditions, the analysis should identify the practical result of the project's non-approval and not create and analyze a set of artificial assumptions that would be required to preserve the existing physical environment."

Thus, under Alternative 4, the No Project alternative would not achieve any NOx reductions, no NOx control equipment would be installed and consequently, no environmental impacts from constructing or operating NOx control equipment would occur. However, if Alternative 4 is implemented, the SCAQMD would be required to seek reductions from as yet unidentified other sources with potential but unknowable adverse impacts.

5.2.5 Alternative 5 – Weighted by BARCT Reduction Contribution

Alternative 5 consists of an across the board NOx RTC reduction (shave) of 14 tpd that would affect all NOx RECLAIM facilities and investors. However, the NOx RTC reductions under this alternative would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. As such, NOx RTC holdings for major refineries and investors would be shaved by 66 ~~67~~ percent and the NOx RTC holdings for non-major refineries and all other facilities would be shaved by 37 ~~36~~ percent. After BARCT is applied, 8.77 ~~8.79~~ tpd of actual NOx reductions are projected to occur, with 5.23 ~~5.21~~ tpd of NOx RTCs needed to fulfill the shave, post-BARCT. By applying a shave of 37 ~~36~~ percent to facilities to non-major facilities, EGFs~~power plants~~, and the bottom 10 percent of RTC holders, 219 ~~210~~ facilities, which represent the bottom 10 percent of RTC holders, would become potential future buyers of RTCs since the amount of RTC holdings for these facilities would become less than their current actual emissions.

Under Alternative 5, the amount of the proposed NOx RTC shave of 14 tpd is identical to the proposed project. However, the distribution of the shave under Alternative 5 would reduce the NOx RTC holdings differently than the proposed project. Specifically, Alternative 5 would reduce NOx RTC holdings by: 1) 66 ~~67~~ percent for 9 refineries and investors (treated as one facility); 2) 37 ~~36~~ percent for 21 EGFs ~~30 power plants~~; 3) 37 ~~36~~ percent for 26 non-major facilities; and, 4) 37 ~~36~~ percent for the remaining 219 ~~210~~ facilities. The proposed project, however, would reduce NOx RTC holdings by: 1) 66 ~~67~~ percent for 9 refineries and investors (treated as one facility); 2) 49 ~~47~~ percent for 21 EGFs~~30 power plants~~; 3) 49 ~~47~~ percent for 26 non-major facilities; and, 4) zero percent for the remaining 219 ~~210~~ facilities.

For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal heat treating furnaces, gas turbines and ICEs not located on the OCS. No new BARCT is proposed for 30 EGFs~~power plants~~. In order to achieve these new BARCT levels, the likely possibility is that operators of 20 facilities with the affected source categories will reduce actual NOx emissions via physical modifications to a wide variety of equipment by installing new air pollution control equipment or modifying existing air pollution control equipment. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. In particular to the number and type of control equipment that may be installed as a result of the proposed project and the corresponding adverse impacts that were analyzed for the proposed project, the same control equipment and corresponding adverse impacts will also occur under Alternative 5.

Table 5-1
Summary of Proposed Project & Alternatives

Components of Proposed Project		**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**NOx Reduction Potential** *(tons/day)*	**Alternative 1: Across the Board Shave** ***(All facilities reduce 53%)***	**NOx Reduction Potential** *(tons/day)*	**Alternative 2: Most Stringent Shave** ***(All facilities reduce 60%)***	**NOx Reduction Potential** *(tons/day)*	**Alternative 3: Industry Approach** ***(All facilities reduce 33%)***	**NOx Reduction Potential** *(tons/day)*
Proposed NOx RTC "Shave"			**14.00**		**14.00**		**15.87**		**8.00**
Basic Equipment	**BARCT**								
FCCU	SCR or LoTOx™ with WGS	2 ppmv NOx at 3% O2	0.43	Same as proposed project	0.43	Same as proposed project	0.43	Same as proposed project	0.43
Refinery Boilers/ Heaters	SCR	2 ppmv NOx, or 0.002 lb NOx/mmBTU	0.94 ~~0.96~~	Same as proposed project	0.94 ~~0.96~~	Same as proposed project	0.94 ~~0.96~~	Same as proposed project	0.94 ~~0.96~~
Refinery Gas Turbines	SCR or SCR Catalyst	2 ppmv NOx at 15% O2	4.14	Same as proposed project	4.14	Same as proposed project	4.14	Same as proposed project	4.14
SRU/TGU	LoTOx™ with WGS or SCR	2 ppmv NOx at 3% O2, or 95% reduction	0.32	Same as proposed project	0.32	Same as proposed project	0.32	Same as proposed project	0.32
Coke Calciner	LoTOx™ with WGS or Ultracat DGS	10 ppmv at 3% O2	0.17	Same as proposed project	0.17	Same as proposed project	0.17	Same as proposed project	0.17
Glass Melting Furnace	SCR or Ultracat DGS	80% reduction, or 0.024 lb NOx per ton glass produced	0.24	Same as proposed project	0.24	Same as proposed project	0.24	Same as proposed project	0.24
Sodium Silicate Furnace	SCR or Ultracat DGS (without dry sorbent)	80% reduction, or 1.28 lb NOx per ton of glass pulled	0.09	Same as proposed project	0.09	Same as proposed project	0.09	Same as proposed project	0.09
Metal Heat Treating Furnace	SCR	9 ppmv at 3% O2, or 0.011 lb NOx/mmBTU	0.56	Same as proposed project	0.56	Same as proposed project	0.56	Same as proposed project	0.56
ICEs (Non-Refinery/Non-Power Plant)	SCR	11 ppmv NOx at 15% O2, 0.041 lb NOx/mmBTU, or 43.05 lb NOx/MMcf	0.84	Same as proposed project	0.84	Same as proposed project	0.84	Same as proposed project	0.84
Gas Turbines (Non-Refinery/ Non-Power Plant)	SCR	2 ppmv NOx at 15% O2	1.04	Same as proposed project	1.04	Same as proposed project	1.04	Same as proposed project	1.04
Potential NOx Emission Reductions (BARCT)			**8.77 ~~8.79~~**		**8.77 ~~8.79~~**		**8.77 ~~8.79~~**		**8.77 ~~8.79~~**
NOx RTCs Needed to Fulfill Shave Post-BARCT			**5.23 ~~5.21~~**		**5.23 ~~5.21~~**		**7.10 ~~7.08~~**		**0**

Key: SCR = Selective Catalytic Reduction; WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber
ppmv = parts per million by volume; mmBTU = million British Thermal Units; MMcf = million cubic feet

Table 5-1 (concluded)
Summary of Proposed Project & Alternatives

Components of Proposed Project		**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**NOx Reduction Potential** *(tons/day)*	**Alternative 4: No Project**	**NOx Reduction Potential** *(tons/day)*	**Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors**	**NOx Reduction Potential** *(tons/day)*
Proposed NOx RTC "Shave"			**14.00**		**0**		**14.00**
Basic Equipment	**BARCT**						
FCCU	SCR or LoTOx™ with WGS	2 ppmv NOx at 3% O2	0.43	No NOx limit	0	Same as proposed project	0.43
Refinery Boilers/ Heaters	SCR	2 ppmv NOx, or 0.002 lb NOx/mmBTU	0.94 ~~0.96~~	No NOx limit	0	Same as proposed project	0.94 ~~0.96~~
Refinery Gas Turbines	SCR or SCR Catalyst	2 ppmv NOx at 15% O2	4.14	No NOx limit	0	Same as proposed project	4.14
SRU/TGU	LoTOx™ with WGS	2 ppmv NOx at 3% O2, or 95% reduction	0.32	No NOx limit	0	Same as proposed project	0.32
Coke Calciner	LoTOx™ with WGS or Ultracat DGS	10 ppmv at 3% O2	0.17	No NOx limit	0	Same as proposed project	0.17
Glass Melting Furnace	SCR or Ultracat DGS	80% reduction, or 0.024 lb NOx per ton glass produced	0.24	No NOx limit	0	Same as proposed project	0.24
Sodium Silicate Furnace	SCR or Ultracat DGS (without dry sorbent)	80% reduction, or 1.28 lb NOx per ton of glass pulled	0.09	No NOx limit	0	Same as proposed project	0.09
Metal Heat Treating Furnace	SCR	9 ppmv at 3% O2, or 0.011 lb NOx/mmBTU	0.56	No NOx limit	0	Same as proposed project	0.56
ICEs (Non-Refinery/Non-Power Plant)	SCR	11 ppmv NOx at 15% O2, 0.041 lb NOx/mmBTU, or 43.05 lb NOx/MMcf	0.84	No NOx limit	0	Same as proposed project	0.84
Gas Turbines (Non-Refinery/ Non-Power Plant)	SCR	2 ppmv NOx at 15% O2	1.04	No NOx limit	0	Same as proposed project	1.04
Potential NOx Emission Reductions			**8.77 ~~8.79~~**		**0**		8.77 ~~8.79~~
NOx RTCs Needed to Fulfill Shave Post-BARCT			**5.23 ~~5.21~~**		**0**		**5.23 ~~5.21~~**

Key: WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber

Key: SCR = Selective Catalytic Reduction; WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber

ppmv = parts per million by volume; mmBTU = million British Thermal Units; MMcf = million cubic feet

5.3 ALTERNATIVES ANALYSIS

The following subsections include the same environmental topic areas evaluated for the proposed project. Under each environmental topic area, impacts and significance conclusions are summarized for the proposed project. In addition, potential impacts generated by each alternative to that environmental topic are described, a significance determination is made for the alternative, and environmental impacts from each alternative are compared to the environmental impacts identified for the proposed project.

5.3.1 Aesthetics

The potential aesthetics impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of aesthetics impacts from each alternative relative to the proposed project.

5.3.1.1 Proposed Project

Potential direct and indirect aesthetics impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.1 – Aesthetics.

Physical modifications may result as part of implementing the proposed project and will vary depending on the equipment source category/process. The aesthetics analysis in this CEQA document is based on the assumption that new air pollution control equipment is expected to be installed and existing air pollution control equipment is expected to be modified as part of implementing the proposed project. Aesthetic impacts associated with the installation of new or the modification of existing NOx control, were identified in the NOP/IS to be potentially significant and, as such, are evaluated in this PEA.

Implementation of the proposed project is expected to result in construction activities at some or all of the affected facilities, which are complex industrial facilities. Due to the large size profiles of the affected equipment, the construction activities associated with installing control equipment are expected to require the use of heavy-duty construction equipment, such as cranes, which may temporarily change the skyline of the affected facilities, depending on where they are located within each facility's property. However, because each affected facility is located in a heavy industrial area, the construction equipment is not expected to be substantially discernable from what would be needed for routine operations and maintenance activities. For these reasons, the construction activities are expected to blend in with the existing industrial environment and thus, are not expected to affect the visual continuity of the surrounding areas.

In addition, for any installation of a WGS, operational aesthetic impacts resulting from a substantial visible steam (water vapor) plume that would emanate from the WGS stack were evaluated in this PEA. The analysis will show that if any WGS is installed as part of the proposed project at any of the affected facilities, the steam plume, though visible, is not expected to significantly adversely affect the visual continuity of the surrounding area of each affected facility because no scenic highways or corridors exist within the areas of the refineries, the coke calciner, the sulfuric acid plants and the glass melting plant. Further, the visual continuity of the surrounding area is not expected to be adversely impacted because each WGS, if constructed, will be built within the confines of industrial areas and would be visually consistent with the profiles of the existing affected facilities. Thus, even if each WGS could be visible, depending on the location within each property boundary, the aesthetic significance criteria would not be exceeded. For these reasons, less than significant aesthetics impacts during operation are expected from the proposed project.

Overall, the aesthetics impacts were determined to be less than significant during both construction and operation for the proposed project.

5.3.1.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. Thus, since the aesthetics impacts were determined to be less than significant during both construction and operation for the proposed project, the aesthetics impacts were determined to be less than significant during both construction and operation under Alternative 1.

5.3.1.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with greater adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

Thus, analysis of Alternative 2 contains the same number and type of control equipment that may be installed as a result of the proposed project and the same corresponding adverse impacts that were analyzed for the proposed project

Thus, since the aesthetics impacts were determined to be less than significant during both construction and operation for the proposed project, the aesthetics impacts were determined to be less than significant during both construction and operation under Alternative 2.

5.3.1.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

Thus, since the aesthetics impacts were determined to be less than significant during both construction and operation for the proposed project, the aesthetics impacts were determined to be less than significant during both construction and operation under Alternative 3.

5.3.1.5 Alternative 4 – No Project

Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of aesthetics would be expected. Thus, no significant impacts to aesthetics resources would be expected to occur under Alternative 4.

5.3.1.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. Thus, since the aesthetics impacts were determined to be less than significant during both construction and operation for the proposed project, the aesthetics impacts were determined to be less than significant during both construction and operation under Alternative 5.

5.3.2 Air Quality and GHG Emissions

The potential direct and indirect air quality and GHG emissions impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of direct and indirect air quality and GHG emissions impacts from each alternative relative to the proposed project.

5.3.2.1 Proposed Project

Potential direct and indirect air quality and GHG emissions impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.2 - Air Quality and Greenhouse Gases.

The proposed project is expected to result in a total of 14 tpd of NOx RTC reductions from the current RTC holdings of 26.5 tpd, to be implemented over a seven-year period from 2016 to 2022. For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will only affect 56 ~~65~~ facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 219 ~~210~~ facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified for the types of equipment and source categories at these facilities. By following this approach, the shave of NOx RTC holdings is distributed as follows:

- 66 ~~67~~% shave for 9 refineries and investors (treated as one facility)
- 49 ~~47~~% shave for 21 EGFs~~30 power plants~~
- 49 ~~47~~% shave for 26 non-major facilities
- 0% shave for 219 ~~210~~ remaining facilities

SCAQMD staff has conducted a BARCT analysis for all 275 facilities and of these, 21 out of 30 EGFs ~~power producing facilities where~~ were shown to operate at current BARCT or BACT levels. For 224 non-power plant facilities plus 9 EGFs for a total of 233 facilities, either no new BARCT was identified or the installation of control equipment was determined to not be cost-effective. Further, only 35 ~~44~~ facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact. In addition, the sale and/or purchase of RTCs by investors (treated as one facility) will also have no environmental impact.

To reduce NOx from the remaining 21 facilities (e.g., 275 – 21 EGFs (with shave) ~~30 power producers~~ – 224 non-power plant facilities – 9 EGFs (without shave) = 21) which are either major or large sources of NOx for which new BARCT has been identified, the BARCT analysis found that it would be both feasible and cost-effective for facility operators to install new control equipment or modify existing control equipment at 20 facilities with 11 facilities belonging to the non-refinery sector and 9 facilities belonging to the refinery sector[2].

As a result, operators of these 20 facilities may choose to modify existing equipment by retrofitting with air pollution control technologies in order to comply with the shave of NOx RTCs. The physical changes involved that may occur as a result of implementing the proposed project focus on the installation of new or the modification of existing control equipment on the following types of equipment and processes: 1) fluid catalytic cracking units; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. Table 1-2 summarizes the potential NOx control technologies that may be considered as part of implementing the proposed project.

Table 5-2

Potential NOx Control Devices Per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Potential NOx Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	SCR LoTOx™ with WGS LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	SCR
Refinery	Refinery Gas Turbines	SCR
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	LoTOx™ with WGSs SCR
Refinery	Petroleum Coke Calciner	LoTOx™ with WGS UltraCat with DGS
Non-Refinery	Container Glass Melting Furnaces	SCR UltraCat with DGS
Non-Refinery	Sodium Silicate Furnaces	SCR UltraCat with DGS
Non-Refinery	Metal Heat Treating Furnaces	SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	SCR
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	SCRs

Construction activities associated with installing or modifying existing air pollution control equipment are expected and have the potential to generate significant adverse air quality impacts. In addition, operational activities due to periodic truck trips such as the delivery of supplies to support the operations of the various control technologies and the removal of waste from the control processes for disposal or recycling are also expected and have the potential to generate significant adverse air quality impacts for greenhouse gases (GHGs).

[2] Since one facility is no longer operating, the analysis is based on 20 facilities, instead of 21 facilities.

With regard to GHG emissions, the proposed project involves combustion processes which could generate GHG emissions such as CO2, CH4, and N2O. However, the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs or PFCs. Implementing the proposed project is expected to increase GHG emissions that exceed the SCAQMD's GHG significance threshold for industrial sources. In addition, implementing the proposed project is expected to generate significant adverse cumulative GHG air quality impacts.

5.3.2.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

The analysis of the proposed project concluded that construction activities associated with installing or modifying existing air pollution control equipment are expected and have the potential to generate significant adverse air quality impacts. In addition, the analysis of the proposed project concluded that operational activities due to periodic truck trips such as the delivery of supplies to support the operations of the various control technologies and the removal of waste from the control processes for disposal or recycling are also expected and have the potential to generate significant adverse air quality impacts for greenhouse gases (GHGs).

Thus, since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction were determined to be significant under Alternative 1. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts were also determined to be significant under Alternative 1.

5.3.2.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with fewer adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

The analysis of the proposed project concluded that construction activities associated with installing or modifying existing air pollution control equipment are expected and have the potential to generate significant adverse air quality impacts. In addition, the analysis of the proposed project concluded that operational activities due to periodic truck trips such as the delivery of supplies to support the operations of the various control technologies and the removal of waste from the control processes for disposal or recycling are also expected and have the potential to generate significant adverse air quality impacts for GHGs.

Thus, since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction were determined to be significant under Alternative 2. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts were also determined to be significant under Alternative 2.

5.3.2.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

The analysis of the proposed project concluded that construction activities associated with installing or modifying existing air pollution control equipment are expected and have the potential to generate significant adverse air quality impacts. In addition, the analysis of the proposed project concluded that operational activities due to periodic truck trips such as the delivery of supplies to support the operations of the various control technologies and the removal of waste from the control processes for disposal or recycling are also expected and have the potential to generate significant adverse air quality impacts for GHGs.

Thus, since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction were determined to be significant under Alternative 3. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts were also determined to be significant under Alternative 3.

5.3.2.5 Alternative 4 – No Project

Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of air quality and GHGs would be expected. However, because Alternative 4 is the continued implementation of the 2005 amendments to the NOx RECLAIM program, no additional NOx emissions would occur even SCAQMD is required to conduct a BARCT assessment in accordance with Health and Safety Code ~~§~~§40440~~ and 39616~~[3] that demonstrates achievable NOx emission reductions. Thus, without any additional NOx reductions, no benefits to air quality and GHG emissions would occur. Although there are other existing rules that may have future compliance dates for NOx emission reductions, potential adverse impacts from these rules have already been evaluated in the Final Program EIR for the 2012 AQMP and their subsequent rule-specific CEQA documents. While air quality would continue to improve to a certain extent, it is unlikely that all state or federal ozone standards would be achieved as required by the federal and California CAAs. It is possible that the federal 24-hour PM2.5 standard may be achieved; however, it is unlikely that further progress would be made towards achieving the state PM2.5 standard as required by the California CAA.

5.3.2.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

The analysis of the proposed project concluded that construction activities associated with installing or modifying existing air pollution control equipment are expected and have the potential to generate significant adverse air quality impacts. In addition, the analysis of the proposed project concluded that operational activities due to periodic truck trips such as the delivery of supplies to support the operations of the various control technologies and the

[3] The reference to Health and Safety Code §39616 has been deleted because it does not require a BARCT analysis. The RECLAIM program proposed here satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so.

removal of waste from the control processes for disposal or recycling are also expected and have the potential to generate significant adverse air quality impacts for GHGs.

Thus, since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction were determined to be significant under Alternative 5. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts were also determined to be significant under Alternative 5.

5.3.3 Energy

The potential energy impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of the energy impacts from each alternative relative to the proposed project.

5.3.3.1 Proposed Project

Potential direct and indirect energy impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.3 - Energy.

During installation or modification of add-on air pollution control devices, adverse energy impacts (e.g., increased demand in energy) may occur during construction due to the need for: 1) diesel fuel to operate onsite construction equipment that cannot utilize or access electricity; 2) diesel fuel to operate heavy-duty and medium-duty vehicles for delivering supplies and hauling waste during construction; and, 3) gasoline to operate offsite vehicles used for worker commuting. The analysis of the proposed project concluded that these projected increased usages of diesel fuel and gasoline would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, these projected increased usages of diesel fuel and gasoline would not create any significant effects on peak and base period demands on the availability of diesel fuel and gasoline.

After the add-on air pollution control devices are installed and operating, adverse energy impacts (e.g., increased demand in energy) may occur during operation due to the need for: 1) electricity to operate the air pollution control devices; and, 2) diesel fuel to operate heavy-duty and medium-duty vehicles for delivering supplies and hauling waste during operation. The analysis of the proposed project concluded that the increased use of electricity and diesel fuel during operation would not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for electricity usage, implementation of the proposed project is expected to have less than significant energy impacts during operation.

5.3.3.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential

NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

The analysis of the proposed project concluded that there would be increased usages of diesel fuel and gasoline and these projected increases would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, these projected increased usages of diesel fuel and gasoline during construction would not create any significant effects on peak and base period demands on the availability of diesel fuel and gasoline. In addition, the analysis of the proposed project concluded that the increased use of electricity and diesel fuel during operation would also not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for electricity usage, implementation of the proposed project is expected to have less than significant energy impacts during operation.

Thus, since the energy impacts during construction and operation were determined to be less than significant for the proposed project, the air quality impacts during construction and operation were also determined to be less than significant under Alternative 1.

5.3.3.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with fewer adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

The analysis of the proposed project concluded that there would be increased usages of diesel fuel and gasoline and these projected increases would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, these projected increased usages of diesel fuel and gasoline during construction would not create any significant effects on peak and base period demands on the availability of diesel fuel and gasoline. In addition, the analysis of the proposed project concluded that the increased use of electricity and diesel fuel during operation would also not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for electricity usage, implementation of the proposed project is expected to have less than significant energy impacts during operation.

Thus, since the energy impacts during construction and operation were determined to be less than significant for the proposed project, the air quality impacts during construction and operation were also determined to be less than significant under Alternative 2.

5.3.3.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

The analysis of the proposed project concluded that there would be increased usages of diesel fuel and gasoline and these projected increases would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, these projected increased usages of diesel fuel and gasoline during construction would not create any significant effects on peak and base period demands on the availability of diesel fuel and gasoline. In addition, the analysis of the proposed project concluded that the increased use of electricity and diesel fuel during operation would also not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for electricity usage, implementation of the proposed project is expected to have less than significant energy impacts during operation.

Thus, since the energy impacts during construction and operation were determined to be less than significant for the proposed project, the air quality impacts during construction and operation were also determined to be less than significant under Alternative 3.

5.3.3.5 Alternative 4 – No Project

Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of energy would be expected. Thus, no significant impacts to energy would be expected to occur under Alternative 4.

5.3.3.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

The analysis of the proposed project concluded that there would be increased usages of diesel fuel and gasoline and these projected increases would not create any significant effects on local or regional energy supplies and on requirements for additional energy. Further, these projected increased usages of diesel fuel and gasoline during construction would not create any significant effects on peak and base period demands on the availability of diesel fuel and gasoline. In addition, the analysis of the proposed project concluded that the increased use of electricity and diesel fuel during operation would also not exceed the significance threshold of one percent of supply. Since the proposed project would not exceed the SCAQMD's energy threshold of one percent of supply for electricity usage, implementation of the proposed project is expected to have less than significant energy impacts during operation.

Thus, since the energy impacts during construction and operation were determined to be less than significant for the proposed project, the air quality impacts during construction and operation were also determined to be less than significant under Alternative 5.

5.3.4 Hazards and Hazardous Materials

The potential hazards and hazardous materials impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of hazards and hazardous materials impacts from each alternative relative to the proposed project.

5.3.4.1 Proposed Project

Potential hazards and hazardous materials impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.4 - Hazards and Hazardous Materials.

Several components with regard to reducing NOx emissions by installing new or modifying existing NOx controls as part of implementing the proposed project may affect the use, storage and transport of hazards and hazardous materials during operational-related activities. Thus, the routine transport of hazardous materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project. The key effects of implementing the proposed project and the determination of which aspects involve hazards and hazardous materials focus on: 1) the anticipated increase of substances used to operate the new or modified NOx controls; and, 2) the increased capture of hazardous substances as part of the overall NOx reduction effort. The analysis of hazards and hazardous materials impacts concluded that the proposed project is expected to generate less than significant adverse impacts related to any of the hazardous substances, such as ammonia and sodium hydroxide, which may be used to operate NOx control equipment.

5.3.4.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

The analysis of hazards and hazardous materials impacts concluded that the proposed project is expected to generate less than significant adverse impacts related to any of the hazardous substances, such as ammonia and sodium hydroxide, which may be used to operate NOx control equipment.

Thus, since the hazards and hazardous materials impacts were determined to be less than significant for the proposed project, the hazards and hazardous materials impacts were also determined to be less than significant under Alternative 1.

5.3.4.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with fewer adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

The analysis of hazards and hazardous materials impacts concluded that the proposed project is expected to generate less than significant adverse impacts related to any of the hazardous substances, such as ammonia and sodium hydroxide, which may be used to operate NOx control equipment. Thus, since the hazards and hazardous materials impacts were determined to be less than significant for the proposed project, the hazards and hazardous materials impacts were also determined to be less than significant under Alternative 2.

5.3.4.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

The analysis of hazards and hazardous materials impacts concluded that the proposed project is expected to generate less than significant adverse impacts related to any of the hazardous substances, such as ammonia and sodium hydroxide, which may be used to operate NOx control equipment.

Thus, since the hazards and hazardous materials impacts were determined to be less than significant for the proposed project, the hazards and hazardous materials impacts were also determined to be less than significant under Alternative 3.

5.3.4.5 Alternative 4 – No Project

Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of hazards and hazardous materials would be expected. Thus, no significant impacts to hazards and hazardous would be expected to occur under Alternative 4.

5.3.4.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

The analysis of hazards and hazardous materials impacts concluded that the proposed project is expected to generate less than significant adverse impacts related to any of the hazardous substances, such as ammonia and sodium hydroxide, which may be used to operate NOx control equipment.

Thus, since the hazards and hazardous materials impacts were determined to be less than significant for the proposed project, the hazards and hazardous materials impacts were also determined to be less than significant under Alternative 5.

5.3.5 Hydrology and Water Quality

The potential hydrology and water quality impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of the hydrology and water quality impacts from each alternative relative to the proposed project.

5.3.5.1 Proposed Project

Potential hydrology and water quality materials impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.5 - Hydrology and Water Quality.

The proposed project is expected to result in the installation of the following new NOx air pollution control equipment: up to 117 SCRs, eight LoTOx^{TM} with WGSs, one LoTOx^{TM} without WGS, and three UltraCat DGSs. During installation these add-on air pollution control devices, adverse hydrology and water quality impacts may occur during construction due to the need for water for dust suppression. Depending on the proposed location within each facility's boundaries for the siting of any new control equipment that may be installed as a result of implementing the proposed project, construction activities such as digging, earthmoving, grading, slab pouring, or paving could occur if the proposed site for the new equipment is not suitable in its present form (e.g., graded with a foundation slab). However, for the few facility operators that may choose to modify or replace their existing NOx control equipment, site preparation activities are not expected because the existing foundation and the existing equipment are expected to be reused in their current location and current plot space. Therefore, no water for dust suppression purposes is expected to be needed for any construction upgrades to existing NOx control equipment.

The potential increase in water use for the facilities that may need to conduct watering for dust suppression activities is below the SCAQMD's significance thresholds of five million gallons per day of total water (e.g., potable, recycled, and groundwater) and 262,820 gallons per day of potable water. The amount of water that may be used on a daily basis for dust suppression activities during construction is less than significant.

Once constructed, but prior to operation of the new or modified air pollution control equipment, additional water is expected to be used to hydrostatically (pressure) test all storage tanks and pipelines, that are installed as part of support equipment to the air pollution control equipment, to ensure each structure's integrity and wastewater may be created during the testing. Pressure testing is typically a one-time event, unless a leak is found. The potential increase in water use for all 20 facilities conducting hydrotesting activities is estimated to be 353,724 gallons per day, which is less than the SCAQMD's significance thresholds of five million gallons per day of total water but greater than 262,820 gallons per day of potable water. Thus, the amount of water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is significant.

Any wastewater generated from hydrotesting or pressure testing is expected to flow to each affected facility's wastewater treatment or collection system and recycled or discharged after treatment with process wastewater. Thus, wastewater generation from pressure testing activities is not expected to affect groundwater quality. Further, the volume of wastewater that will be generated from pressure testing is expected to be minimal and within the capacity of each facility's wastewater treatment and collection systems. Also, because the proposed project is expected to disturb substantially less than one acre per facility, on-site collection of storm water in each facility's storm water collection system is expected to be about the same as the amount currently collected. Therefore, no significant impacts are expected from wastewater generation or storm water during construction.

Of the technologies proposed as BARCT for NOx control, only WGSs utilize water and generate wastewater as part of their day-to-day operations. For this reason, only WGS technology was identified as having the potential to generate adverse hydrology and water quality operational impacts. The analysis shows that WGS technology may be installed for two FCCUs, five SRU/TGUs, and one coke calciner at seven facilities in the refinery sector. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the actual water demand and wastewater impacts may only occur at six of the seven facilities analyzed. However, for the non-refinery sector, WGS technology was not identified as BARCT for the affected equipment.

For water demand, there are three significance thresholds based on whether: 1) the total water demand of the proposed project is less than five million gallons per day; 2) the existing water supply has the capacity to meet the increased demands of the proposed project; and, 3) the potable water demand is less than 262,820 gallons per day. The analysis shows that the increased potential demand for total water during operation that may result from implementing the proposed project either during operation is not expected to exceed the significance threshold of five million gallons of total water demand per day.

Because the projected installation of WGS technology is expected to only occur at one of the two FCCUs, the corresponding increased water demand projections that were originally contemplated for one of the two FCCUs (e.g., Refineries 4 and 9) identified in Tables 4.5-9 and 4.5-10 are no longer expected to occur. Thus, the potential increase in operational water demand is expected to be less. To protect the identity of the refinery in this document, the revised potential increase in operational water demand has been presented as a range, from 553,499 gallons per day to 558,978 gallons per day, instead of 602,814 gallons per day as shown in Table 4.5-9.

Thus, ~~However,~~ the increased potential demand for potable water during operation of the WGS technology at six of the seven refineries originally analyzed ~~facilities~~ is estimated to be from 553,499 gallons per day to 558,978 ~~602,814~~ gallons per day, which exceeds the potable water threshold of 262,820 gallons per day. Of this amount, three ~~of the seven~~ refineries (e.g., Refineries 1, 5, and 6) have current access to recycled water. Should operators of these three refineries ~~facilities~~ commit to utilizing recycled water in lieu of potable water to satisfy the water demand for the NOx control equipment, then, their water suppliers would be able to supply the additional water (e.g., 398,767 gallons per day or approximately 71 ~~66~~ percent of the projected water demand) with recycled water.

Thus, while the amount of water demand that would be needed to operate NOx control equipment would be 398,767 gallons per day at Refineries 1, 5 and 6 and the amount of water demand at Refineries ~~Facilities~~ 2, 4, 8, and 9 would be in the range of 113,836 gallons per day to 160,211 ~~204,047~~ gallons per day, which collectively is greater ~~less~~ than the significance threshold of 262,820 gallons per day of potable water and less than the significance threshold of five million gallons per day of total water (e.g., potable, recycled, and groundwater), in consideration that Refineries 1, 5 and 6 have a high potential to use recycled water because of their current access and in light of the negotiations for recycled water at Refineries 4, 8, and 9, potable water only may be needed for a future project occurring at Refinery 2, or not at all if operators of Refinery 2 choose to install a DGS instead of a WGS. ~~it is not known at this time whether~~ In any case, the previous analysis shows that the water purveyors would be able to supply potable water to ~~for~~Refinery 2 and to Refineries 1, 4, 5, 6, 8 and 9, if needed. ~~these facilities and it is unknown whether all of the water used at the other three refineries would necessarily consist of recycled water. Because of the drought and the uncertainty of future water supplies, it is not clear at this time whether water suppliers would be able to accommodate the additional operational water demand if the proposed project goes forward, especially if potable water or groundwater would be relied upon to supply the water demand.~~ Thus, using an abundance of caution, because the peak daily water demand for the proposed project exceeds the potable water threshold of 262,820 gallons per day and because recycled water is not currently available at Refineries 4, 8 and 9, and no contractual commitments to increase recycled water demand above the existing recycled water baseline for the three refineries that already have access to recycled water (e.g., Refineries 1, 5 and 6) have been finalized, ~~For this reason,~~ the analysis conservatively concludes that ~~the amount of water that may be needed to operate WGS technology may create~~ significant adverse hydrology (water demand) impacts are expected from the proposed project during operation.

Relative to water quality, each affected facility provided their wastewater discharge limits and these limits were compared to each facility's estimated potential increase in wastewater that may result from implementing the proposed project. The peak percentage increase from baseline levels when compared to the proposed project was approximately nine ~~12~~ percent (Refinery 2~~9~~). An increase of 25 percent would trigger a permit revision and would be considered a significant adverse wastewater impact. Since all of the affected facilities have been shown to have a potential wastewater increase less than 25 percent, no modifications to any existing wastewater discharge permits are anticipated as a result of the proposed project. Thus, the operational impacts of the proposed project on each affected facility's wastewater discharge and the Industrial Wastewater Discharge Permit are expected to be less than significant. It is important to note that operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the installation of WGS technology along with the corresponding increased wastewater generation projections that were originally contemplated for one of the two FCCUs (e.g., Refineries 4 and 9) identified in Tables 4.5-9 and 4.5-10 are no longer expected to occur. Thus, the potential increase in operational wastewater generation is expected to be less. To protect the identity of the refinery in this document, the revised potential increase in operational wastewater generation will be reduced from 236,719 gallons per day to 214,801 gallons per day instead. Nonetheless, this reduction in operational wastewater generation will lessen the impacts further than what was analyzed at the time the Draft PEA was released for public review and comment. For this reason, the wastewater impacts from the proposed project are expected to be less than significant.

In conclusion, significant adverse water demand impacts are expected during hydrotesting (post-construction) and during operation. Further, less than significant impacts during construction are expected for water demand and wastewater and less than significant impacts during operation are expected for wastewater.

5.3.5.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

In particular to the topic of hydrology and water quality, only 6~~7~~ of the 20 affected facilities would be expected to have water demand and water quality impacts as a result of the WGS technology that may be installed at these facilities in response to the proposed project. Further, the same 6~~7~~ facilities that may be affected by the proposed project and the same NOx control technology that may be installed as a result of the proposed project (e.g., WGSs) will also be occur under Alternative 1. Finally, the types and amounts of NOx control equipment that may be installed at the 6~~7~~ facilities and their corresponding environmental impacts and conclusions in response to the proposed project are also identical to Alternative 1.

The analysis of hydrology and water quality concluded that the proposed project is expected to generate: 1) significant adverse water demand impacts during hydrotesting (post-construction) and during operation; 2) less than significant water demand impacts during for dust suppression activities; and, 3) less than significant impacts during construction and operation for wastewater. Thus, since the analysis of hydrology and water quality impacts concluded that significant water demand impacts would occur during hydrotesting and during operation, and less than significant water demand impacts would occur during construction, the hydrology and water quality impacts analysis under Alternative 1 may also have significant water demand impacts during hydrotesting and operation, and less than significant water demand impacts during construction. Similarly, since the analysis of hydrology and water quality impacts concluded that less than significant water quality impacts would occur during construction and operation, less than significant water quality impacts during construction and operation would also be expected to occur under Alternative 1.

5.3.5.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with fewer adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

In particular to the topic of hydrology and water quality, only 6~~7~~ of the 20 affected facilities would be expected to have water demand and water quality impacts as a result of the WGS technology that may be installed at these facilities in response to the proposed project. Further, the same 6~~7~~ facilities that may be affected by the proposed project and the same NOx control technology that may be installed as a result of the proposed project (e.g., WGSs) will also be occur under Alternative 2. Finally, the types and amounts of NOx control equipment that may be installed at the 6~~7~~ facilities and their corresponding environmental impacts and conclusions in response to the proposed project are also identical to Alternative 2.

The analysis of hydrology and water quality concluded that the proposed project is expected to generate: 1) significant adverse water demand impacts during hydrotesting (post-construction) and during operation; 2) less than significant water demand impacts during for dust suppression activities; and, 3) less than significant impacts during construction and operation for wastewater. Thus, since the analysis of hydrology and water quality impacts concluded that significant water demand impacts would occur during hydrotesting and during operation, and less than significant water demand impacts would occur during construction, the hydrology and water quality impacts analysis under Alternative 2 may also have significant water demand impacts during hydrotesting and operation, and less than significant water demand impacts during construction. Similarly, since the analysis of hydrology and water quality impacts concluded that less than significant water quality impacts would occur during construction and operation, less than significant water quality impacts during construction and operation would also be expected to occur under Alternative 2.

5.3.5.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

In particular to the topic of hydrology and water quality, only 6 ~~seven~~ of the 20 affected facilities would be expected to have water demand and water quality impacts as a result of the WGS technology that may be installed at these facilities in response to the proposed project. Further, the same 6 ~~seven~~ facilities that may be affected by the proposed project and the same NOx control technology that may be installed as a result of the proposed project (e.g., WGSs) may possibly occur under Alternative 3. Finally, the types and amounts of WGS equipment that may be installed at the 6 ~~seven~~ facilities and their corresponding environmental impacts and conclusions in response to Alternative 3 could be the same or less than the proposed project.

The analysis of hydrology and water quality concluded that the proposed project is expected to generate: 1) significant adverse water demand impacts during hydrotesting (post-construction) and during operation; 2) less than significant water demand impacts during for dust suppression activities; and, 3) less than significant impacts during construction and operation for wastewater. Thus, since the analysis of hydrology and water quality impacts concluded that significant water demand impacts would occur during hydrotesting and during operation, and less than significant water demand impacts would occur during construction, the hydrology and water quality impacts analysis under Alternative 3 may also have significant water demand impacts during hydrotesting and operation, and less than significant water demand impacts during construction. Similarly, since the analysis of hydrology and water quality impacts concluded that less than significant water quality impacts would occur during construction and operation, less than significant water quality impacts during construction and operation would also be expected to occur under Alternative 3.

5.3.5.5 Alternative 4 – No Project

Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of hydrology and water quality would be expected. Thus, no significant impacts to hydrology and water quality would be expected to occur under Alternative 4.

5.3.5.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

In particular to the topic of hydrology and water quality, only 6~~7~~ of the 20 affected facilities would be expected to have water demand and water quality impacts as a result of the WGS technology that may be installed at these facilities in response to the proposed project. Further, the same 6~~7~~ facilities that may be affected by the proposed project and the same NOx control technology that may be installed as a result of the proposed project (e.g., WGSs) will also be occur under Alternative 5. Finally, the types and amounts of NOx control equipment that may be installed at the 6~~7~~ facilities and their corresponding environmental impacts and conclusions in response to the proposed project are also identical to Alternative 5.

The analysis of hydrology and water quality concluded that the proposed project is expected to generate: 1) significant adverse water demand impacts during hydrotesting (post-construction) and during operation; 2) less than significant water demand impacts during for dust suppression activities; and, 3) less than significant impacts during construction and operation for wastewater. Thus, since the analysis of hydrology and water quality impacts concluded that significant water demand impacts would occur during hydrotesting and during operation, and less than significant water demand impacts would occur during construction, the hydrology and water quality impacts analysis under Alternative 5 may also have significant water demand impacts during hydrotesting and operation, and less than significant water demand impacts during construction. Similarly, since the analysis of hydrology and water quality impacts concluded that less than significant water quality impacts would occur during construction and operation, less than significant water quality impacts during construction and operation would also be expected to occur under Alternative 5.

5.3.6 Solid and Hazardous Waste

The potential solid and hazardous waste impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of solid and hazardous waste impacts from each alternative relative to the proposed project.

5.3.6.1 Proposed Project

Potential solid and hazardous waste impacts from the proposed project are summarized in the following subsections. For the complete analysis, refer to Subchapter 4.6 – Solid and Hazardous Waste. The analysis in Subchapter 4.6 identified the following activities that have the potential to generate adverse solid hazardous waste impacts during construction and operation:

Construction activities associated with installing NOx control equipment such as demolition and site preparation/grading/excavating could generate solid waste as result of implementing the proposed project. However, the amount of debris generated during construction at 20 facilities would not be expected to exceed the designated capacity of local landfills. For this reason, the construction impacts of the proposed project on waste treatment/disposal facilities were concluded to be less than significant.

Solid waste may also be generated from the operation of the new NOx air pollution control equipment at both the refinery and non-refinery facilities. Further, it is possible that some, if not all, of the 20 affected facilities will address any increase in waste through their existing waste minimization plans. For example, some of the affected facilities in both the refinery and non-refinery sectors currently have existing catalyst-based operations and the spent catalysts are either regenerated, reclaimed or recycled, in lieu of disposal, and this practice would be expected to continue. The overall impacts of the proposed project on waste treatment/disposal facilities due to solid waste that may be generated from both refinery and non-refinery facilities during construction and operation were concluded to be less than significant.

Overall, it was concluded in Subchapter 4.6 that potential solid and hazardous waste impacts from implementing the proposed project would be less than significant. Therefore, project-specific solid and hazardous waste impacts associated with the proposed project are less than significant.

5.3.6.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

Thus, since the solid and hazardous waste impacts were determined to be less than significant during both construction and operation for the proposed project, the solid and hazardous impacts were also determined to be less than significant during both construction and operation under Alternative 1.

5.3.6.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with fewer adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

Thus, since the solid and hazardous waste impacts were determined to be less than significant during both construction and operation for the proposed project, the solid and hazardous impacts were also determined to be less than significant during both construction and operation under Alternative 2.

5.3.6.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

Thus, since the solid and hazardous waste impacts were determined to be less than significant during both construction and operation for the proposed project, the solid and hazardous impacts were also determined to be less than significant during both construction and operation under Alternative 3.

5.3.6.5 Alternative 4 – No Project

Alternative 4 would continue the implementation of the 2005 amendments to the NOx RECLAIM program. Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of solid and hazardous waste would be expected. Thus, no significant impacts to solid and hazardous waste would be expected to occur under Alternative 4.

5.3.6.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

Thus, since the solid and hazardous waste impacts were determined to be less than significant during both construction and operation for the proposed project, the solid and hazardous impacts were also determined to be less than significant during both construction and operation under Alternative 5.

5.3.7 Transportation and Traffic

The potential direct and indirect transportation and traffic impacts from implementing the proposed project and the project alternatives were evaluated. The following subsections provide brief discussions of direct and indirect hazards and hazardous materials impacts from each alternative relative to the proposed project.

5.3.7.1 Proposed Project

Potential direct and indirect transportation and traffic impacts from the proposed project are summarized in the following subsections. For the complete analysis, refer to Subchapter 4.7 – Transportation and Traffic.

Implementation of the proposed project may cause adverse transportation and traffic impacts associated with the existing facilities affected by the proposed project. Specifically, construction-based traffic associated with the installation of NOx control technology are expected from construction workers, delivery trucks and haul trucks. During operation of the proposed project, regular deliveries and waste disposal activities are also expected to increase at each of the affected facilities. Despite the increases, the analysis shows that the transportation and traffic impacts, though adverse, are less than significant for the proposed project during both construction and operation.

5.3.7.2 Alternative 1 – Across the Board Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 1, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 1 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 1. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

Thus, since the transportation and traffic impacts were determined to be less than significant during both construction and operation for the proposed project, the transportation and traffic impacts were also determined to be less than significant during both construction and operation under Alternative 1.

5.3.7.3 Alternative 2 – Most Stringent Shave of NOx RTCs

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 2, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 2 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 2. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical. However, it is possible that under this alternative, facilities could increase their level of control to obtain a compliance margin which would result in a greater air quality benefit from NOx reductions with fewer adverse environmental impacts. Nonetheless, because the quantity and type of NOx control equipment that may be installed beyond what was analyzed for the proposed project is speculative, any potential increased environmental benefit and corresponding impacts that may occur from increasing the level of control to obtain a compliance margin beyond what has been analyzed for the proposed project cannot be analyzed.

Thus, since the transportation and traffic impacts were determined to be less than significant during both construction and operation for the proposed project, the transportation and traffic impacts were also determined to be less than significant during both construction and operation under Alternative 2.

5.3.7.4 Alternative 3 – Industry Approach

Because not as many, if any, additional actual NOx emission reductions would be needed to achieve an overall NOx RTC shave of 8.0 tpd, fewer than the 20 facilities that may be affected by the proposed project will be affected by Alternative 3. Without knowing exactly how industry will react if Alternative 3 is implemented, to predict the number of facilities that would install NOx control equipment would be speculative and unquantifiable. However, to conduct a worst-case analysis without quantification, the number and type of control equipment that may be installed under Alternative 3 is assumed to be fewer than what was analyzed for the proposed project and the corresponding adverse impacts under Alternative 3 would also be fewer than what was analyzed for the proposed project. To be conservative, the same conclusions reached for the proposed project for each environmental topic area will be applied to Alternative 3, except that the impacts will be concluded to have fewer impacts than the proposed project.

Thus, since the transportation and traffic impacts were determined to be less than significant during both construction and operation for the proposed project, the transportation and traffic impacts were also determined to be less than significant during both construction and operation under Alternative 3.

5.3.7.5 Alternative 4 – No Project

Alternative 4 would continue the implementation of the 2005 amendments to the NOx RECLAIM program. Under the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of transportation and traffic would be expected. Thus, no significant impacts to transportation and traffic would be expected to occur under Alternative 4.

5.3.7.6 Alternative 5 – Weighted by BARCT Reduction Contribution

Despite the differences in how facilities are affected by the NOx RTC shave and the amount of the NOx RTC shave under Alternative 5, the amount of potential NOx emission reductions that may be achieved by installing new or modifying existing air pollution control equipment under Alternative 5 is 8.77 ~~8.79~~ tpd, which is identical to the amount of potential NOx emissions reductions estimated for the proposed project. The same 20 facilities that may be affected by the proposed project will also be affected under Alternative 5. Further, the types and amounts of NOx control equipment that may be installed at the 20 affected facilities and their corresponding environmental impacts and conclusion are also identical.

Thus, since the transportation and traffic impacts were determined to be less than significant during both construction and operation for the proposed project, the transportation and traffic impacts were also determined to be less than significant during both construction and operation under Alternative 5.

5.4 COMPARISON OF THE PROPOSED PROJECT TO THE ALTERNATIVES

Pursuant to CEQA Guidelines §15126.6 (d), a CEQA document "shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project. A matrix displaying the major characteristics and significant environmental effects of each alternative may be used to summarize the comparison. If an alternative would cause one or more significant effects in addition to those that would be caused by the project as proposed, the significant effects of the alternative shall be discussed, but in less detail than the significant effects of the project as proposed." Accordingly, Table 5-3 provides a matrix displaying the major characteristics and significant environmental effects of the proposed project and each alternative.

Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the projected installation of WGS technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of SCRs that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potential adverse environmental impacts summarized in Table 5-3.

Table 5-3

Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Aesthetics	Visible steam plumes and new, tall stacks from installing/operating up to 8 WGSs at 7 facilities as follows: FCCU: 2 WGSs SRU/TGU: 5 WGSs Coke Calciner: 1 WGS	Same as proposed project	Same as proposed project, but if facility operators install additional WGSs beyond what is analyzed for the proposed project to obtain a compliance margin, then additional steam plumes and tall stacks could occur.	Less than proposed project	No installation of WGSs (e.g., no visible steam plumes and no new, tall stacks) expected	Same as proposed project
Aesthetics Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project, but potentially more adverse aesthetics impacts if facility operators install additional WGSs beyond what is analyzed for the proposed project)	Less than significant (less than proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)
Air Quality & GHGs	• Reduces total operational NOx emissions by 8.77 ~~8.79~~ tpd • Reduces total NOx RTC holdings by 14.0 tpd • Unused NOx RTCs to be applied to shave is 5.23 ~~5.21~~ tpd • Increases total GHGs by: - 41,785 MT/yr without mitigation; & - 41,100 MT/yr with mitigation • Increases operational use of NaOH (a TAC) by 5.84 tpd	Same as proposed project	• Reduces total operational NOx emissions by 8.77 ~~8.79~~ tpd • Reduces total NOx RTC holdings by 15.87 tpd • Unused NOx RTCs to be applied to shave is 7.10 ~~7.08~~ tpd • Increases total GHGs by: • - 41,785 MT/yr without mitigation; & - 41,100 MT/yr with mitigation • Increases operational use of NaOH (a TAC) by 5.84 tpd	• Less operational NOx reductions than proposed project but not quantifiable • Reduces total NOx RTC holdings by 8.00 tpd • Less increases to GHGs than proposed project, but not quantifiable before or after mitigation • Less increases in operational use of NaOH (a TAC) but not quantifiable	• No decreases in total operational NOx emissions. • No increases in construction emissions for any pollutant.	Same as proposed project

Table 5-3 (continued)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Air Quality & GHGs (concluded)	• Increases operational use of NH3 (a TAC) by 39.5 tpd • Increases peak daily operation emissions as follows: VOC: 17 lb/day CO: 75 lb/day NOx: 190 lb/day* PM10: 22 lb/day PM2.5: 19 lb/day • Increases peak daily emissions for construction in same year as follows: VOC: 429 lb/day CO: 2,745 lb/day NOx: 1,656 lb/day SOx: 3 lb/day PM10: 1,758 lb/day without mitigation; & 853 ~~1,009~~ lb/day with mitigation PM2.5: 883 lb/day without mitigation; & 430 ~~508~~ lb/day with mitigation	Same as proposed project	• Increases operational use of NH3 (a TAC) by 39.5 tpd Increases peak daily operation emissions as follows: VOC: 17 lb/day CO: 75 lb/day NOx: 190 lb/day* PM10: 22 lb/day PM2.5: 19 lb/day • Increases peak daily emissions for construction in same year as follows: VOC: 429 lb/day CO: 2,745 lb/day NOx: 1,656 lb/day SOx: 3 lb/day PM10: 1,758 lb/day without mitigation; & 853 ~~1,009~~ lb/day with mitigation PM2.5: 883 lb/day without mitigation; & 430 ~~508~~ lb/day with mitigation • If additional controls are installed beyond the proposed project for a compliance margin, more emission benefits as well as increased emissions impacts could occur.	• Less increases in operational use of NH3 (a TAC) but not quantifiable • Less increases in peak daily operation emissions but not quantifiable • Less increases in peak daily emissions for construction but not quantifiable with or without mitigation	• No decreases in total operational NOx emissions • No increases in construction emissions for any pollutant.	Same as proposed project

* The potential increases in NOx operational emissions are more than offset by the overall project reductions.

Table 5-3 (continued)

Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	**Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities**	**Alternative 1: Across the Board Shave *(All facilities reduce 53%)***	**Alternative 2: Most Stringent Shave *(All facilities reduce 60%)***	**Alternative 3: Industry Approach *(All facilities reduce 33%)***	**Alternative 4: No Project**	**Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors**
Air Quality & GHG Impacts Significant?	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd. • Less than significant for VOC, CO, PM10 and PM2.5 during operation • Significant for GHGs • Less than significant for TACs use (NaOH and NH3) during operation • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd (same as proposed project) • Less than significant for VOC, CO, PM10 and PM2.5 during operation (same as proposed project) • Significant for GHGs (same as proposed project) • Less than significant for TACs use (NaOH and NH3) during operation (same as proposed project) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (same as proposed project)	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd (same as proposed project) • Less than significant for VOC, CO, PM10 and PM2.5 during operation (same as proposed project) • Significant for GHGs (same as proposed project) • Less than significant for TACs use (NaOH and NH3) during operation (same as proposed project) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (same as proposed project) • If additional controls are installed beyond the proposed project for a compliance margin, more emission benefits and increased emissions could occur.	• Less than significant; achieves net NOx emission reductions during operation (less reductions than the proposed project but not quantifiable) • Less than significant increases in VOC, CO, PM10 and PM2.5 during operation (less than the proposed project but not quantifiable) • Significant for GHGs, (less than proposed project but not quantifiable) • Less than significant for TACs use (NaOH and NH3) during operation (less than the proposed project but not quantifiable) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (less than proposed project but not quantifiable)	• No Impact - Not Significant • Does not achieve required AQMP NOx emission reductions during operation • Does not comply with BARCT assessment requirements per Health and Safety Code	• Less than significant, achieves net NOx emission reductions during operation by 8.72 tpd (same as proposed project) • Less than significant for VOC, CO, PM10 and PM2.5 during operation (same as proposed project) • Significant for GHGs(same as proposed project) • Less than significant for TACs use (NaOH and NH3) during operation (same as proposed project) • Significant for VOC, CO, NOx, PM10, and PM2.5 during construction (same as proposed project)

Table 5-3 (continued)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Energy	• During construction: -Increased use of diesel by 15,855 gal/day -Increase use of gasoline by 5,422 gal/day • During operation: -Increased use of electricity by 214 MWh/day -Increased use of diesel by 8,380 gal/day	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, increased energy use during construction and operation could occur	Less than the proposed project	No increases in energy uses during construction or operation	Same as proposed project
Energy Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased energy use than the proposed project could occur.)	Less than significant (less than the proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)
Hazards & Hazardous Materials	Increased use of 5.84 tons/day of NaOH and 39.5 tons/day of NH3 (both TACs) used during operation.	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional NaOH and NH3 may be needed.	Less than the proposed project	No change to existing hazards and hazardous materials used	Same as proposed project
Hazards & Hazardous Materials Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased use of NaOH and NH3 could occur.)	Less than significant	No Impact - Not Significant	Less than significant (same as proposed project)

Table 5-3 (continued)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Hydrology & Water Quality	• During construction: -Increased use of water for dust suppression by 12,501 gal/day -Increased use of water for hydrotesting by 353,724 gal/day • During operation -Increased use of potable water by 553,499 to 558,978 ~~602,814~~ gal/day (of which 512,603 up to 518,082 ~~204,047~~ gal/day could potentially be supplied by recycled water) -Increased generation of wastewater by 214,801 ~~236,719~~ gal/day.	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional water demand and increased wastewater generation may occur.	Less than the proposed project	No change to existing water demand or wastewater discharge	Same as proposed project
Hydrology & Water Quality Impacts Significant?	• Significant for water demand during hydrotesting (assuming entire demand is based on potable water) • Significant for water demand during operation (assuming entire demand is based on potable water) • Less than significant for water demand during construction • Less than significant for wastewater discharge during construction and operation	-Significant for water demand (same as proposed project) -Less than significant for wastewater discharge (same as proposed project)	-Significant for water demand (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased use of water during construction and operation may be needed) -Less than significant for wastewater discharge (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, then additional wastewater may be discharged	-Significant for water demand (less than proposed project) -Less than significant for wastewater discharge (less than proposed project)	No Impact - Not Significant	-Significant for water demand (same as proposed project) -Less than significant for wastewater discharge (same as proposed project)

Table 5-3 (concluded)
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic Area	Proposed Project: Shave Applied to 90 percent of RTC Holders – 56 ~~65~~ facilities	Alternative 1: Across the Board Shave *(All facilities reduce 53%)*	Alternative 2: Most Stringent Shave *(All facilities reduce 60%)*	Alternative 3: Industry Approach *(All facilities reduce 33%)*	Alternative 4: No Project	Alternative 5: Weighted by BARCT Reduction Contribution for all facilities & investors
Solid & Hazardous Waste	• During construction: -Increased generation of non-hazardous solid waste • During operation: -Increased generation of non-hazardous solid waste that can be recycled	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional solid waste may be generated.	Less than the proposed project	No change to existing disposal of solid & hazardous waste	Same as proposed project
Solid & Hazardous Waste Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if additional controls are installed beyond the proposed project for a compliance margin, increased use of water during construction and operation may be needed)	Less than significant (less than the proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)
Transportation & Traffic	Overall peak increase in transportation and traffic of 485 trips per day during construction and 65 trips per day during operation.	Same as proposed project	Same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional daily trips during construction and operation may be needed.	Less than the proposed project	No change to existing transportation and traffic.	Same as proposed project
Transportation & Traffic Impacts Significant?	Less than significant	Less than significant (same as proposed project)	Less than significant (same as proposed project but if facility operators install additional NOx controls beyond what is analyzed for the proposed project to obtain a compliance margin, additional daily trips during construction and operation may be needed)	Less than significant (less than the proposed project)	No Impact - Not Significant	Less than significant (same as proposed project)

5.5 ALTERNATIVES REJECTED AS INFEASIBLE

In accordance with CEQA Guidelines §15126.6 (c), a CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and briefly explain the reasons underlying the lead agency's determination. Section 15126.6 (c) also states that among the factors that may be used to eliminate alternatives from detailed consideration in a CEQA document are: 1) failure to meet most of the basic project objectives; 2) infeasibility; or, 3) inability to avoid significant environmental impacts.

As noted in Section 5.1, the range of feasible alternatives to the proposed project is limited by the nature of the proposed project and associated legal requirements. Similarly, the range of alternatives considered, but rejected as infeasible is also relatively limited. The following subsection identifies Alternative 4 to the proposed project, as being rejected due to infeasibility for the reasons explained in the following subsection.

5.5.1 Alternative 4 - No Project

CEQA documents typically assume that the adoption of a No Project alternative would result in no further action on the part of the project proponent or lead agency. For example, in the case of a proposed land use project such as a housing development, adopting the No Project alternative terminates further consideration of that housing development or any housing development alternative identified in the associated CEQA document. In that case, the existing setting would typically remain unchanged.

The concept of taking no further action (and thereby leaving the existing setting intact) by adopting a No Project alternative does not readily apply to implementation of a control measure that has been adopted and legally mandated in the 2012 AQMP. ~~Adopting a No Project alternative for implementing a control measure in the 2012 AQMP does not automatically imply that no further action will be taken (e.g., halting implementation of the existing 2012 AQMP).~~ The federal and state Clean Air Acts require the SCAQMD to implement the AQMP in order to attain all state and national ambient air quality standards. More importantly, ~~Thus,~~ a No Project alternative in the case of the proposed project is not a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources~~undermines the legal requirements in the 2012 AQMP. Consequently, the No Project alternative presented in this Draft PEA is the continued implementation of the 2005 amendments to the NOx RECLAIM program. Further, it is also unclear whether or not continued implementation of the 2005 amendments to the NOx RECLAIM program is a feasible alternative because the SCAQMD is required to conduct a BARCT reassessment in accordance with Health and Safety Code §§40440 and 39616 that demonstrates achievable NOx emission reductions.~~

"The 'no project' analysis shall discuss the existing conditions at the time the notice of preparation is published, or if no notice of preparation is published, at the time environmental analysis is commenced, *as well as what would be reasonably expected to occur in the foreseeable future if the project were not approved, based on current plans and consistent with available infrastructure and community services*…" It should be noted that, except for air quality and GHG emissions, there would be no further incremental impacts on the existing environment if no further action is taken. Although there are other existing rules that may have future compliance dates for NOx emission reductions, potential adverse impacts from these rules have already been evaluated in the Final Program EIR for the 2012 AQMP and their subsequent rule-specific CEQA documents. While air quality would continue to improve to a certain extent, it is unlikely that all state or federal ozone standards would be achieved as required by the federal and California CAAs. It is possible that the federal 24-hour PM2.5 standard may be achieved; however, it is unlikely that further progress would be made towards achieving the state PM2.5 standard as required by the California CAA.

5.6 LOWEST TOXIC AND ENVIRONMENTALLY SUPERIOR ALTERNATIVE

5.6.1 Lowest Toxic Alternative

In accordance with SCAQMD's policy document Environmental Justice Program Enhancements for FY 2002-03, Enhancement II-1 recommends for all SCAQMD CEQA documents which are required to include an alternatives analysis, the alternative analysis shall also include and identify a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous or toxic air pollutants.

As explained in Subchapter 4.4 – Hazards and Hazardous Materials, implementation of the proposed project may alter the hazards and hazardous materials associated with the existing facilities affected by the proposed project. Air pollution control equipment and related devices are expected to be installed or modified at affected facilities such that their operations may increase the quantity of materials used in the control equipment, some of which are hazardous. . The main NOx reduction technologies considered for the proposed project are based on employing mostly SCR and WGS technologies. The analysis shows that of the possible NOx controls that may be employed, both SCR and WGS technologies may increase the use of toxic materials such as aqueous ammonia and sodium hydroxide (NaOH), respectively. In addition, one UltraCat DGS that may be considered for Refinery 2 would also utilize aqueous ammonia for its operation. Some WGSs, but not all, rely on the use of sodium hydroxide (NaOH) caustic solution as the scrubbing agent. NaOH is a toxic air contaminant (TAC) that is a non-cancerous but acutely hazardous substance and is used in WGSs for controlling NOx emissions from FCCUs, SRU/TGUs, coke calciners, and glass melting. Despite the potential increased use in ammonia and NaOH, the overall analysis concluded that the proposed project would generate less than significant adverse hazards and hazardous materials impacts.

To identify a lowest toxic alternative with respect to the proposed project, a lowest toxic alternative would be if NOx control technologies are employed that use the least amount of hazardous or toxic materials However, because each of the alternatives, except Alternative 3 – Industry Approach and Alternative 4 – the No Project alternative, assumes that the same type and amounts of NOx control equipment on at the same affected facilities will be installed, the amount of hazardous materials that may be needed to operate the various NOx control equipment under each alternative (except for Alternatives 3 and 4) would also be the same. While Alternative 3 results in fewer toxic emissions, it is not the environmentally superior alternative because it results in far fewer NOx benefits than the proposed project, which already has less than significant toxic impacts.

As explained in subsection 5.3.4.5, under Alternative 4, the No Project alternative, no new NOx limits are proposed for any equipment/source category and no NOx RTC reductions are proposed. Thus, none of the 20 facilities that would be affected by the proposed project would be affected by Alternative 4 to the extent that no control equipment would be installed or modified, and no adverse impacts from construction and operating the new or modified control equipment would be expected to occur. Since no construction or operation activities associated with new or modified control equipment would occur under Alternative 4, no new impacts to the environment, including the topic of hazards and hazardous materials would be expected. Thus, no increased use in the amount of hazardous or toxic materials would occur if Alternative 4 is implemented.

Thus, from a hazard and air toxics perspective, when compared to the proposed project and the other alternatives under consideration, if implemented, Alternative 4 is considered to be the lowest toxic alternative, but it is not the environmentally superior alternative because it does not achieve that NOx reductions that would result from the proposed project.

5.6.2 Environmentally Superior Alternative

Pursuant to CEQA Guidelines §15126.6 (e)(2), if the environmentally superior alternative is the "no project" alternative, the CEQA document shall also identify an alternate environmentally superior alternative from among the other alternatives. Alternative 4, the No Project alternative, would result in the continued implementation of the 2005 amendments to the NOx RECLAIM program and is considered to be the least toxic alternative because it is not expected to generate any significant adverse impacts to any environmental topic areas without providing any environmental benefits.

Alternative 4, the No Project alternative, is not the environmentally superior alternative because it does not achieve the NOx reductions as the proposed project or Alternatives 1, 2 and 5. However, if the amount of shave that would be applied by each of these alternatives is taken into consideration as an indicator to how facility operators may respond to the reduced amount of available NOx RTCs in the market, then the alternative with highest amount of proposed shave of NOx RTC holdings, Alternative 2, would have the greatest chance of ensuring that all control equipment that is contemplated would be installed in order to ensure that the maximum amount of NOx emissions reductions projected would actually occur. Thus, of Alternatives 1, 2, 3 and 5, Alternative 2 would be considered the environmentally superior alternative.

5.7 CONCLUSION

Of the five alternatives analyzed, Alternative 4 would generate the least severe and fewest number of environmental impacts compared to the proposed project. However, of the project alternatives, Alternative 4 would achieve the fewest of the project objectives and would have the fewest NOx reduction benefits.

Alternatives 1, 2, and 5 would all be expected to generate equivalent impacts to proposed project in all environmental topic areas analyzed. Alternative 3 would provide the least amount of actual NOx emission reductions (except for the Alternative 4 – the No Project alternative), while Alternative 2 would provide the greatest amount of actual NOx emission reductions. Alternatives 1, 2, 3, and 5 all propose to shave the NOx RTC holdings of 219 ~~210~~ facilities which represent the bottom 10 percent of NOx RTC holders. By applying a shave in this manner, the 219 ~~210~~ facilities would become potential future buyers of RTCs since the amount of RTC holdings for these facilities would become less than their current actual emissions for Alternatives 1, 2, 3 and 5. For this reason, none of Alternatives 1, 2, 3 and 5 would satisfy Objective No. 2 "to modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment" (the project objectives are described on page 2-4 in Chapter 2). Thus, the proposed project is considered to provide the best balance between emission reductions and the adverse environmental impacts due to construction and operation activities while meeting the objectives of the project. Therefore, the proposed project is preferred over the project alternatives.

CHAPTER 6

REFERENCES

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Organizations and Persons Consulted

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6.1 ORGANIZATIONS AND PERSONS CONSULTED

The CEQA statutes and Guidelines require that organizations and persons consulted be provided in the PEA. A number of organizations, state and local agencies, and private industry have been consulted. The following organizations and persons have provided input into this document.

Steven Mac
California Energy Commission

Uzi Daniel and Joe Walters
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Edward Hutter
Dupont

Rob Wood
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Long Beach Water Department

Sean Gamette
Port of Long Beach

CHAPTER 7

ACRONYMS

7.0 ACRONYMS

ABBREVIATION = DESCRIPTION

μg/m3 = micrograms per cubic meter
ACGIH = American Conference of Governmental Industrial Hygiene
APS = Alternative Planning Strategy
AQMP = Air Quality Management Plan
ASME = American Society of Mechanical Engineers
ATCM = Airborne Toxic Control Measure
ATCP = Air Toxics Control Plan
AVTA = Advanced Vehicle Testing Activity
B100 = biodiesel
BACM = Best Available Control Measure
BACT = Best Available Control Technology
BARCT = Best Available Retrofit Control Technology
BART = Best Available Control Technology
Basin = South Coast Air Basin
BAU = business-as-usual
BLEVE = boiling liquid expanding vapor explosion
BLM = Bureau of Land Management
BMP = best management practice
BPTCP = Bay Protection and Toxic Cleanup Plan
C3H8 = propane
CAA = Clean Air Act
CAFE = Corporate Average Fuel Economy
CalARP = California Accidental Release Prevention Program
CalEMA = California Emergency Management Agency
CalEPA = California Environmental Protection Agency
CalOSHA = California Occupational Safety and Health Administration
Caltrans = California Department of Transportation
CaOH = calcium hydroxide
CAPCOA = California Air Pollution Control Officers Association
CARB = California Air Resources Board
CCAR = California Climate Action Registry
CCP = Clean Communities Plan
CCR = California Code of Regulations
CEC = California Energy Commission
CEMS = continuous emissions monitor system
CEQA = California Environmental Quality Act
CERCLA = Comprehensive Environmental Response, Compensation, and Liability Act
CERs = Certified Emission Reductions

CFR = Code of Federal Regulations
CH4 = methane
CHMIRS = California Hazardous Materials Incident Reporting System
CHP = California Highway Patrol
CI = compressed engines
CIP = Capital Improvement Program
CIWMP = Countrywide Integrated Waste Management Plan
CM = control measure
CMA = Congestion Management Agency
CNG = compressed natural gas
CO = carbon monoxide
CO2 = carbon dioxide
CO2eq = carbon dioxide equivalent
COD = chemical oxygen demand
COHb = carboxyhemoglobin
CPCC = California Portland Cement Company
CPSC = Consumer Products Safety Commision
CPUC = California Public Utilities Commission
CRA = Colorado River Aqueduct
CS2 = carbon disulfide
CUPA = Certified Unified Program Agency
CWA = Clean Water Act
CWAP = Clean Water Action Plan
DC = direct current
DEA = diethanolamine
DFW = Department of Fish and Wildlife
DGS = dry gas scrubber
DHS = Department of Health Services
DPH = Department of Public Heath
DTSC = Department of Toxic Substance Control
DWR = California Department of Water Resources
EA = Environmental Assessment
EAP = Emergency Action Plan
EDV = Electro Dynamic Venturi
EGF = electric generating facility
EIR = Environmental Impact Report
EISA = Energy Independence and Security Act
EJ = Environmental Justice
EJAG = Environmental Justice Advisory Group
EMWD = Eastern Municipal Water District
ERPG = Emergency Response Planning Guidelines
ESP = electrostatic precipitator

EV = electric vehicle
FCCU = fluid catalytic cracking unit
Fe203 = iron oxide
FedOSHA = Federal Occupational Safety and Health Administration
FEMA = Federal Emergency Management Agency
FFV = flexible fuel vehicle
FGT = fuel gas treatment
FHWA = Federal Highway Administration
FR = Federal Register
FUA = Fuel Use Act
gal = gallons
GHG = greenhouse gases
GHGRP = Greehouse Gas Reporting Program
gWh = gigawatt-hour
GWP = global warming potential
H2S = hydrogen sulfide
H2SO4 = sulfuric acid
HAP = hazardous air pollutant
HCFC = hydrochlorofluorocarbon
HCl = hydrochloric acid
HDRD = hydrogeneration-derived renewable diesel
HF = hydrofluoric acid
HMTA = Hazardous Material Transportation Act
HOV = high occupancy vehicle
HRSG = heat recovery steam generation
HSC = Health and Safety Code
HWCL = Hazardous Waste Control Law
HWMP = San Bernardino County's Hazardous Waste Management Plan
ICE = internal combustion engines
IDLH = Immediately Dangerous to Life and Health
inH20 = inches water column
IRP = Integrated Water Resources Plan
IS = Initial Study
kW = kilowatt
kWh = kilowatt-hour
LAA = Los Angeles Aqueduct
LACSD = Los Angeles County Sanitation District
LADWP = Los Angeles Department of Water and Power
LAER = Lowest Achievable Emission Rate
LBGOD = Long Beach Gas and Oil Dept.
LCFS = Low Carbon Fuel Standard
LCP = Local Coastal Program

LEA = Local Enforcement Agencies
LEED = Leadership in Energy and Environmental Design
LEL = lower explosive limit
LEPC = Local Emergency Planning Committee
LOS = level of service
LPG = liquefied petroleum gas
LRP = Local Resources Program
LTCP = Long-Term Conservation Plan
LUP = land use plan
M&I = municipal and industrial
MATES = Multiple Air Toxics Exposure Studies
MCL = Maximum Contaminant Levels
MDAB = Mojave Desert Air Basin
mmBTU or MMBTU = million British Thermal Units
MoO3 = molybdic anhydride
MPO = Metropolitan Planning Organization
MPO = Metropolitan Planning Organizations
MS4s = municipal separate storm sewer systems
MSBACT = Minor Source Best Available Control Technology
MSDS = Material Safety Data Sheet
MTBE = methyl tertiary butyl ether
MW = megawatt
MWD = Metropolitan Water District
N2O = nitrous oxide
Na2CO3 = sodium carbonate
Na2S2O5 = sodium pyrosulfate
Na2SO3 = sodium sulfite
NAAQS = National Ambient Air Quality Standards
NaHSO3 = sodium bisulfite
NaOH = sodium hydroxide
NCP = National Contingency Plan
NECPA = National Energy Conservation Policy Act
NESHAP = National Emission Standard for Hazardous Air Pollutants
NFC = National Fire Code
NFPA = National Fire Protection
NH03 = nitric oxide
NH3 = ammonia
NHTSA = National Highway Traffic and Safety Administration
NIOSH = National Institute for Occupational Safety and Health
NO = nitric oxide
NOP/IS = Notice of Preparation/Initial Study
NOx = oxides of nitrogen

NPDES = National Pollutant Discharge Elimination System
NSCR = non-selective catalytic reduction
NSR = New Source Review
O2 = oxygen
O3 = ozone
OCHCA = Orange County Health Care Agency
OCS = outer continental shelf
OCTA = Orange County Transportation Authority
ODS = ozone depleting substance
OEHA = Office of Environmental Health Hazard Assessment
OES = Office of Emergency Services
OHMS = Office of Hazardous Materials Safety
OPR = Office of Planning and Research
OSHA = Occupational Safety and Health Administration
PAR = Proposed Amended Rule
PAReg = Proposed Amended Regulation
PCU = publicly owned utilities
PEA = Program Environmental Assessment
PEL = permissible exposure limit
PEV = plug-in electric vehicle
PFC = perfluorocarbon
PM = particulate matter
PM10 = particulate matter with an aerodynamic diameter of 10 microns or less
PM2.5 = particulate matter with an aerodynamic diameter of 2.5 microns or less
POTW = publicly-owned treatment works
ppm = parts per million
ppmv = parts per million by volume'
PSD = Prevention of Significant Deterioration
PSM = Process Safety Management
PG&E = Pacific Gas and Electric
PURPA = Public Utilities Regulatory Policies Act
PV = photovoltaic
PVC = polyvinyl chloride
Qfs = qualifying facilities
QSA = Quantification Settlement Agreement
QV = qualified vehicle testers
RCRA = Resource Conservation and Recovery Act
RCTC = Riverside County Transportation Commission
RECLAIM = Regional Clean Air Incentives Market
REL = Reference Exposure Level
RFS = renewable fuel standard
RIN = renewable identification number

RMP = Risk Management Programs
RPS = renewables portfolio standard
RTAC = Regional Target Advisory Committee
RTC = RECLAIM Trading Credit
RTIP = Regional Transportation Improvement Program
RTP = Regional Transportation Plan
RWQCB = Regional Water Quality Control Board
SANBAG = San Bernardino Associated Governments
SCAB = South Coast Air Basin
SCAG = Southern California Association of Governments
SCAQMD = South Coast Air Quality Management District
SCE = Southern California Edison
SCHWMA = Southern California Hazardous Waste Management Authority
SCR = selective catalytic reduction
SCS = sustainable communities strategy
SDG&E = San Diego Gas and Electric
SEA = Supplemental Environmental Assessment
SF6 = sulfur hexafluoride
SGVEWP = San Gabriel Valley Energy Wise Program
SI = spark ignited
SIP = State Implementation Plan
SNCR = selective non-catalytic reduction
SO2 = sulfur dioxide
SO3 = sulfur trioxide
SoCal Gas = San Gabriel Valley Energy Wise Pgram
SOx = oxides of sulfur
SRRE = Source Reduction and Recycling Element
SRU/TGU = sulfur recovery unit/tail gas unit
SSAB = Salton Sea Air Basin
STE = Solar thermal energy
STEL = short-term exposure limits
SWMP = Storm Water Management Plan
SWP = State Water Project
SWPPP = Storm Water Pollution Prevention Plan
SWRCB = State Water Resources Control Board
TDM = Transportation Demand Management
TEA-21 = Transportation Equity Act for the 21st Century
Ti02 = titanium dioxide
TIMP = Transportation Improvement and Mitigation Program
TLVs = Threshold Limit Values
TMCs = Transportation Management Centers
tons/day = tons per day

tpd = tons per day
TRI = Toxic Release Inventory
TSCA = Toxic Substances Control Act
TSS = total suspended solids
TWA = time-weighted average
UEL = upper explosive limt
USC = United States Code
USDOE = United States Department of Energy
USDOT = United States Department of Transportation
USEPA = United States Environmental Protection Agency
USFS = United States Forest Service
V2O5 = vanadium pentoxide
VC = volume-to-capacity
VHT = vehicle hours of travel
VMT = vehicle miles of travel
VOC = Volatile Organic Compounds
WCI = Western Climate Incentive
WDR = waste discharge requirements
WGS = wet gas scrubber

APPENDIX A1

PROPOSED AMENDED RULE 2001 – APPLICABILITY

Since the release of the Draft PEA, new amendments to Rule 2001 are proposed that would include a provision that would allow the owner or operator of an electricity generating facility (EGF) to opt out of the NOx RECLAIM program. In order to save space and avoid repetition, please refer to the latest version of Proposed Amended Rule 2001 located elsewhere in the Governing Board Package.

Original hard copies of the Draft PEA, which do not include the draft version of the proposed amended rule listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX A2

PROPOSED AMENDED RULE 2002 – ALLOCATIONS FOR OXIDES OF NITROGEN (NOX) AND OXIDES OF SULFUR (SOX)

In order to save space and avoid repetition, please refer to the latest version of proposed amended Rule 2002 located elsewhere in the Governing Board Package. The version of Proposed Amended Rule 2002 that was circulated with the Draft PEA and released on August 14, 2015 for a 45-day public review and comment period ending September 29, 2015 was "PAR2002 08072015" dated August 7, 2015.

Original hard copies of the Draft PEA, which include the draft version of the proposed amended rule listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX B

PROPOSED AMENDED RULE 2005 – NEW SOURCE REVIEW FOR RECLAIM

In order to save space and avoid repetition, please refer to the latest version of proposed amended Rule 2005 located elsewhere in the Governing Board Package. The version of Proposed Amended Rule 2005 that was circulated with the Draft PEA and released on August 14, 2015 for a 45-day public review and comment period ending September 29, 2015 was dated July 2015.

Original hard copies of the Draft PEA, which include the draft version of the proposed amended rule listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX C

PROPOSED AMENDED RULE 2011 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF OXIDES OF SULFUR (SOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

In order to save space and avoid repetition, please refer to the latest version of proposed amended Protocol for Rule 2011 located elsewhere in the Governing Board Package. The version of Proposed Amended Rule 2011 Protocol that was circulated with the Draft PEA and released on August 14, 2015 for a 45-day public review and comment period ending September 29, 2015 was (PAR 2011 07222015) dated July 22, 2015.

Original hard copies of the Draft PEA, which include the draft version of the proposed amended protocol listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX D

PROPOSED AMENDED RULE 2012 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF OXIDES OF NITROGEN (NOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

In order to save space and avoid repetition, please refer to the latest version of proposed amended Protocol for Rule 2012 located elsewhere in the Governing Board Package. The version of Proposed Amended Rule 2012 Protocol that was circulated with the Draft PEA and released on August 14, 2015 for a 45-day public review and comment period ending September 29, 2015 was (PAR 2012 07222015) dated July 22, 2015.

Original hard copies of the Draft PEA, which include the draft version of the proposed amended protocol listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX E

CONSTRUCTION AND OPERATION CALCULATIONS)

PROPOSED PROJECT: GRAND TOTALS - OPERATION

SRU/TGUs
4 refineries (Facilities 1, 5,6 & 8) - 5 LoTox with WGSs & 1 SCR

Usage Rates

31,093	kWh/day	Electricity
468,767	gal/day	Water
175,890	gal/day	Wastewater
1,028	Mmbtu/day	Cooling Water
1,233	scf/day	Compressed Air
3.64	tons/day	Solid Waste Disposal
1.39	tons/day	Soda Ash
1397.00	lbs/day	NH3 (aqueous 19%)
25,696	sf	plot space needed
2,100	round trip miles/day	truck miles driven
11	trucks/day	no. of trucks
24,747	round trip miles/year	truck miles driven
96	trucks/year	no. of trucks

FCCU
5 refineries (Facilities 4, 5, 6, 7, & 9) - 3 LoTox w/WGSs & 2 SCRs

Usage Rates

40,543	kWh/day	Electricity
93,151	gal/day	Water
43,836	gal/day	Wastewater
1	Mmbtu/day	Cooling Water
1,479	scf/day	Compressed Air
2.33	tons/day	Solid Waste Disposal
2.47	tons/day	NaOH (50%)
2,794	lbs/day	NH3 (aqueous 19%)
7,950	lbs/day	oxygen
10,959	sf	plot space needed
1,550	round trip miles/day	truck miles driven
11	trucks/day	no. of trucks
20621	round trip miles/year	truck miles driven
135	trucks/year	no. of trucks

Coke Calciner
1 refinery (Facility 2) - 1 Ultracat DGS or 1 LoTox w/WGS

Usage Rates

11,621	kWh/day	Electricity
40896.00	gal/day	Water
16992.00	gal/day	Wastewater
36,576	scf/day	Compressed Air
0.44	tons/day	Solid Waste Disposal
3,068	lbs/day	NH3 (aqueous 19%)
1.81	tons/day	Hydrated Lime Ca(OH)2
3.37	tons/day	NaOH (50%)
1,200	sf	plot space needed
616	round trip miles/day	truck miles driven
4	trucks/day	no. of trucks
6,345	round trip miles/year	truck miles driven
86	trucks/year	no. of trucks

Boilers/Heaters
8 refineries (Facilities 1, 3, 4, 5, 6, 7, 8, & 9) - SCRs

Usage Rates

78,389	kWh/day	Electricity
58,307	lbs/day	NH3 (aqueous 19%)
23,672	sf	plot space needed
2,400	round trip miles/day	truck miles driven
24	trucks/day	no. of trucks
47,900	round trip miles/year	truck miles driven
479	trucks/year	no. of trucks

Gas Turbines
5 refineries (Facilities 1, 4, 5, 6, & 7) - SCRs

Usage Rates		
6,524	kWh/day	Electricity
3,576	lbs/day	NH3 (aqueous 19%)
0	sf	plot space needed
1,500	round trip miles/day	truck miles driven
15	trucks/day	no. of trucks
4,000	round trip miles/year	truck miles driven
40	trucks/year	no. of trucks

GRAND TOTALS (For Operation)

Usage Rates					Notes	Net Effect of Project		Percentage Change	Significant?	
168,170	kWh/day	168.17	MWh/day	Electricity	Significance Threshold: 1% of supply (8362 MW - instantaneous electricity)	7.01	MW (instantaneous)	0.08%	NO	Note 1: Instantaneous Electricity Equation: 168,170 kW-hr/day x 1 work day/24 hr x 1 MW/1000 kW = 7.0 MW. Note 2: This calculation takes into account the electricity needed to make 5.84 tons per day of NaOH to satisfy demand (13,235 kWh/day).
602,814	gal/day	0.60	MMgal/day	Water	Significance Threshold: 5,000,000 gal/day water	602,814	gal/day	12.06%	NO	*See Hydrology/Water Quality Analysis
236,718	gal/day	0.24	MMgal/day	Wastewater	Significance Threshold: 25% increase above permitted wastewater limits	236,718	gal/day	<25%*	NO	*See Hydrology/Water Quality Analysis
		1,029	MMbtu/day	Cooling Water	This data already included in energy calculations.					
		39,288	scf/day	Compressed Air	This data already included in energy calculations.					
		6.41	tons/day	Solid Waste Disposal	Solid Waste Disposal, Air Quality off-site transportation emissions, & Energy (fuel usage)					
		1.39	tons/day	Soda Ash (Na2CO3)	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		5.84	tons/day	NaOH (50% by weight)	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		69,142	lbs/day	NH3 (aqueous 19%)	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		7,950	lbs/day	Oxygen	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		1.81	tons/day	Hydrated Lime Ca(OH)2	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		95,127	sf	Plot Space Needed	Air Quality: grading/site-preparation construction emissions					
		8,166	round trip miles/day	Daily truck miles driven	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		65	trucks/day	Daily no. of trucks	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		103,613	round trip miles/year	Annual truck miles driven	Air Quality: off-site transportation emissions & Energy (fuel usage)					
		836	trucks/year	Annual no. of trucks	Air Quality: off-site transportation emissions & Energy (fuel usage)					

Key:
Cooling water already accounted for in both water demand and energy demand.

NaOH is 50% by weight, usually delivered by tanker truck in an aqueous solution due to high concentration

1 MW = 1000 KW

1 tcf (trillion cubic feet) = 1000 bcf (billion cubic feet) = 1,000,000 MMcf (million cubic feet)
1 metric ton = 2205 lbs

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance (miles/day)	Annual Round-trip Distance (miles/year)	Mileage Rate (miles/ gallon)	2016 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	8,166	103,613	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heavy-Heavy Duty Trucks	11.86	53.12	138.04	0.33	6.93	5.69
TOTAL	**12**	**53**	**138**	**0**	**7**	**6**
Significance Threshold	55	550	55	150	150	150
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	436,025	6.97	436,171	198
TOTAL	**436,025**	**7**	**436,171**	**198**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	8,166	103,613	4.89	1,670	21,189
				TOTAL	**1,670**	**21,189**

Operations - Criteria Pollutants From Electricity Generation

Operation	Peak Daily Electricity Demand (MWh/day)	Simple Cycle Turbine Emission Factors					
Electricity Generation		VOC (lb/MWh)	CO (lb/MWh)	NOx (lb/MWh)	SOx (lb/MWh)	PM10 (lb/MWh)	PM2.5 (lb/MWh)
Electricity Needed by 9 Refineries	168	0.02	0.08	0.09	0.00	0.06	0.06

Incremental Increase in Criteria Pollutant Emissions from Electricty Generation	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Emissions from Electricity Needed by 9 Refineries	3.36	13.45	15.14	0.00	10.09	9.89
TOTAL	**3**	**13**	**15**	**0**	**10**	**10**

Example Calculation: NOx: 0.09 lbs/MWh x 45.3 MWh = 4.08 lbs

OPERATIONAL TRUCK TRIPS BY EQUIPMENT CATEGORY

Operational Truck Trips and Miles Driven			Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
1	Boilers/Heaters	14 SCRs	1	73	100	7,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Boilers/Heaters	2 SCRs	1	9	100	900	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Boilers/Heaters	6 SCRs	1	26	100	2,600	0	0	0	0	1	6	100	600	1	6	100	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Boilers/Heaters	12 SCRs	1	40	100	4,000	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Boilers/Heaters	15 SCRs	1	103	100	10,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Boilers/Heaters	9 SCRs	1	46	100	4,600	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Boilers/Heaters	9 SCRs	1	71	100	7,100	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Boilers/Heaters	7 SCRs	1	29	100	2,900	0	0	0	0	1	9	100	900	1	9	100	900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		BOILER/HEATER SUBTOTALS	**8**	**397**	**800**	**39,700**	**0**	**0**	**0**	**0**	**8**	**41**	**800**	**4,100**	**8**	**41**	**800**	**4,100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

BOILER/HEATER TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	24	479	2,400	47,900

Operational Truck Trips and Miles Driven			Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
2	Coke Calciner	1 Ultracat DGS or 1 LoTox WGS	1	21	100	200	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	1	26	66	1,745	1	32	50	1,600	0	0	0	0
		COKE CALCINER SUBTOTALS	**1**	**21**	**100**	**200**	**1**	**7**	**400**	**2,800**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**26**	**66**	**1,745**	**1**	**32**	**50**	**1,600**	**0**	**0**	**0**	**0**

COKE CALCINER TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	4	86	616	6,345

Operational Truck Trips and Miles Driven			Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
4	FCCU	1 LoTox with WGS	0	0	0	0	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5	50	250				
5	FCCU	1 SCR	1	19	100	1,897	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	FCCU	1 SCR	1	9	100	948	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	FCCU	1 ozone generator for LoTox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	44	50	2,176
9	FCCU	1 LoTox with WGS	0	0	0	0	1	28	400	11,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	19	50	950	0	0	0	0
		FCCU SUBTOTALS	**2**	**28**	**200**	**2,845**	**2**	**35**	**800**	**14,000**	**2**	**2**	**200**	**200**	**2**	**2**	**200**	**200**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**24**	**100**	**1,200**	**1**	**44**	**50**	**2,176**

FCCU TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	11	135	1,550	20,621

Operational Truck Trips and Miles Driven			Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
1	Gas Turbine	1 SCR for Gas Turbine	1	8	100	800	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Gas Turbine	1 SCR for Gas Turbine	1	3	100	300	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gas Turbine	3 SCR for Gas Turbine	1	12	100	1,200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Gas Turbine	1 SCR for Gas Turbine	1	2	100	200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Gas Turbine	1 SCR for Gas Turbine	1	5	100	500	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		GAS TURBINE SUBTOTALS	**5**	**30**	**500**	**3,000**	**0**	**0**	**0**	**0**	**5**	**5**	**500**	**500**	**5**	**5**	**500**	**500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

GAS TURBINE TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	15	40	1,500	4,000

Operational Truck Trips and Miles Driven			Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
1	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	10	400	4,000	0	0	0	0	0	0	0	0	1	4	50	200	0	0	0	0	0	0	0	0				
5	SRU/TGU	2 LoTox with WGSs	0	0	0	0	1	26	400	10,400	0	0	0	0	0	0	0	0	1	10	50	500	0	0	0	0	0	0	0	0				
5	SRU/TGU	1 SCR	1	19	100	1,897	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	SRU/TGU	1 LoTox with WGSs	0	0	0	0	1	13	400	5,200	0	0	0	0	0	0	0	0	1	5	50	250	0	0	0	0	0	0	0	0				
8	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	5	400	2,000	0	0	0	0	0	0	0	0	1	2	50	100	0	0	0	0	0	0	0	0	0	0	0	0
		SRU/TGU SUBTOTALS	**1**	**19**	**100**	**1,897**	**4**	**54**	**1,600**	**21,600**	**1**	**1**	**100**	**100**	**1**	**1**	**100**	**100**	**4**	**21**	**200**	**1,050**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

SRU/TGU TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	11	96	2,100	24,747

	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
GRAND SUBTOTALS	**17**	**495**	**1,700**	**47,642**	**7**	**96**	**2,800**	**38,400**	**16**	**49**	**1,600**	**4,900**	**16**	**49**	**1,600**	**4,900**	**4**	**21**	**200**	**1,050**	**1**	**26**	**66**	**1,745**	**3**	**56**	**150**	**2,800**	**1**	**44**	**50**	**2,176**

GRAND TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	65	836	8,166	103,613

DAILY TRIPS TOTALS	**65**
ANNUAL TRIPS TOTALS	**836**
DAILY MILES TOTALS	**8,166**
ANNUAL MILES TOTALS	**103,613**

OPERATIONAL TRUCK TRIPS BY FACILITY

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
1	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	10	400	4,000	0	0	0	0	0	0	0	0	1	4	50	200	0	0	0	0	0	0	0	0				
1	Gas Turbine	1 SCR for Gas Turbine	1	8	100	800	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Boilers/Heaters	14 SCRs	1	73	100	7,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 1 SUBTOTALS	**2**	**81**	**200**	**8,100**	**1**	**10**	**400**	**4,000**	**2**	**6**	**200**	**600**	**2**	**6**	**200**	**600**	**1**	**4**	**50**	**200**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 1 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	8	107	1,050	13,500	5	215	2,761

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
2	Coke Calciner	1 Ultracat DGS or 1 LoTox WGS	1	21	100	200	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	1	26	66	1,745	1	32	50	1,600	0	0	0	0
		FACILITY 2 SUBTOTALS	**1**	**21**	**100**	**200**	**1**	**7**	**400**	**2,800**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**26**	**66**	**1,745**	**1**	**32**	**50**	**1,600**	**0**	**0**	**0**	**0**

FACILITY 2 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	4	86	616	6,345	5	126	1,298

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
3	Boilers/Heaters	2 SCRs	1	9	100	900	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 3 SUBTOTALS	**1**	**9**	**100**	**900**	**0**	**0**	**0**	**0**	**1**	**1**	**100**	**100**	**1**	**1**	**100**	**100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 3 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	3	11	300	1,100	5	61	225

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
4	FCCU	1 LoTox with WGS	0	0	0	0	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5	50	250				
4	Gas Turbine	1 SCR for Gas Turbine	1	3	100	300	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Boilers/Heaters	6 SCRs	1	26	100	2,600	0	0	0	0	1	6	100	600	1	6	100	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 4 SUBTOTALS	**2**	**29**	**200**	**2,900**	**1**	**7**	**400**	**2,800**	**2**	**7**	**200**	**700**	**2**	**7**	**200**	**700**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**5**	**50**	**250**	**0**	**0**	**0**	**0**

FACILITY 4 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	8	55	1,050	7,350	5	215	1,503

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
5	FCCU	1 SCR	1	19	100	1,897	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	SRU/TGU	2 LoTox with WGSs	0	0	0	0	1	26	400	10,400	0	0	0	0	0	0	0	0	1	10	50	500	0	0	0	0	0	0	0	0				
5	SRU/TGU	1 SCR	1	19	100	1,897	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gas Turbine	3 SCR for Gas Turbine	1	12	100	1,200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Boilers/Heaters	12 SCRs	1	40	100	4,000	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 5 SUBTOTALS	**4**	**90**	**400**	**8,994**	**1**	**26**	**400**	**10,400**	**4**	**8**	**400**	**800**	**4**	**8**	**400**	**800**	**1**	**10**	**50**	**500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 5 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	14	142	1,650	21,494	5	337	4,395

OPERATIONAL TRUCK TRIPS BY FACILITY

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
6	FCCU	1 SCR	1	9	100	948	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	SRU/TGU	1 LoTox with WGSs	0	0	0	0	1	13	400	5,200	0	0	0	0	0	0	0	0	1	5	50	250	0	0	0	0	0	0	0	0				
6	Gas Turbine	1 SCR for Gas Turbine	1	2	100	200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Boilers/Heaters	15 SCRs	1	103	100	10,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 6 SUBTOTALS	**3**	**114**	**300**	**11,448**	**1**	**13**	**400**	**5,200**	**3**	**7**	**300**	**700**	**3**	**7**	**300**	**700**	**1**	**5**	**50**	**250**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 6 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	11	146	1,350	18,298	5	276	3,742

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
7	FCCU	1 ozone generator for LoTox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	44	50	2,176
7	Gas Turbine	1 SCR for Gas Turbine	1	5	100	500	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Boilers/Heaters	9 SCRs	1	46	100	4,600	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 7 SUBTOTALS	**2**	**51**	**200**	**5,100**	**0**	**0**	**0**	**0**	**2**	**6**	**200**	**600**	**2**	**6**	**200**	**600**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**44**	**50**	**2,176**

FACILITY 7 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	7	107	650	8,476	5	133	1,733

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
8	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	5	400	2,000	0	0	0	0	0	0	0	0	1	2	50	100	0	0	0	0	0	0	0	0	0	0	0	0
8	Boilers/Heaters	9 SCRs	1	71	100	7,100	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 8 SUBTOTALS	**1**	**71**	**100**	**7,100**	**1**	**5**	**400**	**2,000**	**1**	**5**	**100**	**500**	**1**	**5**	**100**	**500**	**1**	**2**	**50**	**100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 8 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	5	88	750	10,200	5	153	2,086

	Operational Truck Trips and Miles Driven		Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
Facility	Equipment Category	Control Equipment Assumed to Be Installed	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
9	FCCU	1 LoTox with WGS	0	0	0	0	1	28	400	11,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	19	50	950	0	0	0	0
9	Boilers/Heaters	7 SCRs	1	29	100	2,900	0	0	0	0	1	9	100	900	1	9	100	900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 9 SUBTOTALS	**1**	**29**	**100**	**2,900**	**1**	**28**	**400**	**11,200**	**1**	**9**	**100**	**900**	**1**	**9**	**100**	**900**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**19**	**50**	**950**	**0**	**0**	**0**	**0**

FACILITY 9 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	5	94	750	16,850	5	153	3,446

	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles	Daily Trips	Annual Trips	Daily Miles	Annual Miles
	NH3	NH3	NH3	NH3	Solid Waste	Solid Waste	Solid Waste	Solid Waste	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Fresh Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Spent Catalyst	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Lime	Lime	Lime	Lime	NaOH	NaOH	NaOH	NaOH	Oxygen	Oxygen	Oxygen	Oxygen
GRAND SUBTOTALS	**17**	**495**	**1,700**	**47,642**	**7**	**96**	**2,800**	**38,400**	**16**	**49**	**1,600**	**4,900**	**16**	**49**	**1,600**	**4,900**	**4**	**21**	**200**	**1,050**	**1**	**26**	**66**	**1,745**	**3**	**56**	**150**	**2,800**	**1**	**44**	**50**	**2,176**

GRAND TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	65	836	8,166	103,613	5	1,670	21,189

PROPOSED PROJECT: GHG GRAND TOTALS

Operations - GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use*	**169.25**	**MWh/day**	**Electricity GHGs**	**30,818**	**0**	**0**	**30,818**
Facility 1	41.31	MWh/day	Electricity GHGs	7521.50	0.00	0.00	7,522
Facility 2	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2,116
Facility 3	1.63	MWh/day	Electricity GHGs	296.44	0.00	0.00	296
Facility 4	25.16	MWh/day	Electricity GHGs	4581.72	0.00	0.00	4,582
Facility 5	24.73	MWh/day	Electricity GHGs	4503.61	0.00	0.00	4,504
Facility 6	21.88	MWh/day	Electricity GHGs	3983.72	0.00	0.00	3,984
Facility 7	8.17	MWh/day	Electricity GHGs	1487.28	0.00	0.00	1,487
Facility 8	14.31	MWh/day	Electricity GHGs	2605.14	0.00	0.00	2,605
Facility 9	20.45	MWh/day	Electricity GHGs	3722.77	0.00	0.00	3,723
water - increased use[1]	**0.60**	**MMgal/day**	**Water Conveyance GHGs**	**811.06**	**0.0047**	**0.0085**	**813**
Facility 1	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
Facility 2	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.00	0.00	55
Facility 4	0.05	MMgal/day	Water Conveyance GHGs	66.35	0.0004	0.0007	66
Facility 5	0.22	MMgal/day	Water Conveyance GHGs	294.89	0.0017	0.0031	295
Facility 6	0.11	MMgal/day	Water Conveyance GHGs	147.45	0.0009	0.0015	148
Facility 8	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
Facility 9	0.04	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.0006	59
wastewater - increased generation[1]	**0.24**	**MMgal/day**	**Wastewater Processing GHGs**	**318.49**	**0.0018**	**0.0033**	**319**
Facility 1	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	19
Facility 2	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	23
Facility 4	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
Facility 5	0.10	MMgal/day	Wastewater Processing GHGs	132.70	0.00	0.00	133
Facility 6	0.05	MMgal/day	Wastewater Processing GHGs	66.35	0.00	0.00	66
Facility 8	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	19
Facility 9	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
temporary construction activities[3]	**1372.90**	**MT/project**	**Construction GHGs in CO2e**				**1,373**
Facility 1	313						
Facility 2	82						
Facility 3	31						
Facility 4	97						
Facility 5	363						
Facility 6	181						
Facility 7	85						
Facility 8	85						
Facility 9	136						
operational truck trips	**193.81**	**MT/project**	**Operation GHGs in CO2e**				**194**
Facility 1	26						
Facility 2	12						
Facility 3	2						
Facility 4	14						
Facility 5	37						
Facility 6	35						
Facility 7	16						
Facility 8	19						
Facility 9	32						
						TOTAL CO2e	**33,517**
						Significance Threshold	**10,000**
						Exceed Significance?	**YES**

Operations - GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use*	**169.25**	**MWh/day**	**Electricity GHGs**	**30,818**	**0**	**0**	**30,818**
Facility 1	41.31	MWh/day	Electricity GHGs	7521.50	0.00	0.00	7521.50
Facility 2	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2115.96
Facility 3	1.63	MWh/day	Electricity GHGs	296.44	0.00	0.00	296.44
Facility 4	25.16	MWh/day	Electricity GHGs	4581.72	0.00	0.00	4581.72
Facility 5	24.73	MWh/day	Electricity GHGs	4503.61	0.00	0.00	4503.61
Facility 6	21.88	MWh/day	Electricity GHGs	3983.72	0.00	0.00	3983.72
Facility 7	8.17	MWh/day	Electricity GHGs	1487.28	0.00	0.00	1487.28
Facility 8	14.31	MWh/day	Electricity GHGs	2605.14	0.00	0.00	2605.14
Facility 9	20.45	MWh/day	Electricity GHGs	3722.77	0.00	0.00	3722.77
water - increased use[2]	**0.60**	**MMgal/day**	**Water Conveyance GHGs**	**325.23**	**0.0019**	**0.0034**	**326**
Facility 1	0.070	MMgal/day	Water Conveyance GHGs	8.90	0.0001	0.0001	9
Facility 2	0.041	MMgal/day	Water Conveyance GHGs	55.024	0.000	0.001	55
Facility 4	0.049	MMgal/day	Water Conveyance GHGs	66.35	0.00	0.00	66
Facility 5	0.219	MMgal/day	Water Conveyance GHGs	27.86	0.0002	0.0003	28
Facility 6	0.110	MMgal/day	Water Conveyance GHGs	13.93	0.00	0.00	14
Facility 8	0.070	MMgal/day	Water Conveyance GHGs	94.18	0.00	0.00	94
Facility 9	0.044	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.0006	59
wastewater - increased generation[2]	**0.24**	**MMgal/day**	**Wastewater Processing GHGs**	**121.22**	**0.0007**	**0.0013**	**121**
Facility 1	0.01	MMgal/day	Wastewater Processing GHGs	1.78	0.0000	0.0000	2
Facility 2	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	22.91
Facility 4	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	29.55
Facility 5	0.10	MMgal/day	Wastewater Processing GHGs	12.54	0.0001	0.0001	13
Facility 6	0.05	MMgal/day	Wastewater Processing GHGs	6.27	0.00	0.00	6.28
Facility 8	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	18.84
Facility 9	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.0002	0.0003	30
temporary construction activities[3]	**1372.90**	**MT/project**	**Construction GHGs in CO2e**				**1,373**
Facility 1	313.30						
Facility 2	81.67						
Facility 3	30.88						
Facility 4	97.11						
Facility 5	362.91						
Facility 6	181.46						
Facility 7	84.93						
Facility 8	84.93						
Facility 9	135.71						
operational truck trips	**193.81**	**MT/project**	**Operation GHGs in CO2e**				**194**
Facility 1	25.77						
Facility 2	12.11						
Facility 3	2.10						
Facility 4	14.03						
Facility 5	37.03						
Facility 6	34.93						
Facility 7	16.18						
Facility 8	19.47						
Facility 9	32.17						
						TOTAL CO2e	**32,832**
						Significance Threshold	**10,000**
						Exceed Significance?	**YES**

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO_2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH_4/MMscf fuel burned
1,110 lb CO_2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO_2/MWh for electricity use due to water conveyance
0.0067 lb CH_4/MWh for electricity use due to water conveyance
0.0037 lb N_2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

Facility 1	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
SRU/TGU	Subtotal for 1 LoTox with WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Gas Turbine	Subtotal for 1 SCR for Gas Turbine	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	Subtotal for 4 SCRs	16	83	84	0	6	6	5	5	1,503	287	195,360	37,326
	Subtotal for 5 containment berms					236	92	118	46				
	TOTAL FOR FACILITY 1	**56**	**338**	**209**	**0**	**274**	**130**	**137**	**65**	**2,356**	**697**	**316,573**	**145,165**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**				

*For Facility 1, a total of 15 SCRs (14 for Boilers/Heaters and 1 for 1 Gas Turbine) could be installed, but peak construction is based on a 1/3rd overlap of 15 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 2	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
Coke Calciner	Subtotal for 1 Ultracat DGS or 1 LoTOx WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
	TOTAL FOR FACILITY 2	**36**	**233**	**104**	**0**	**30**	**30**	**12**	**12**	**478**	**339**	**72,373**	**98,508**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**NO**	**NO**				

Facility 3	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
Boilers/Heaters*	Subtotal for 2 SCRs	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 2 containment berms					95	37	47	18				
	TOTAL FOR FACILITY 3	**8**	**42**	**42**	**0**	**98**	**40**	**50**	**21**	**751**	**144**	**97,680**	**18,663**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**				

*For Boilers/Heaters, Facility 3 could install 2 new SCRs so peak construction is based on construction of both units overlapping at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 4	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	**Construction Emissions Summary**	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 Unmitigated (lb/day)**	**PM10 Mitigated (lb/day)**	**PM2.5 Unmitigated (lb/day)**	**PM2.5 Mitigated (lb/day)**	**Total Diesel Fuel Usage (gal/day)**	**Total Gasoline Fuel Usage (gal/day)**	**Total Diesel Fuel Usage (gal/project)**	**Total Gasoline Fuel Usage (gal/project)**
FCCU	**Subtotal for 1 LoTox with WGS**	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Gas Turbine	**Subtotal for 1 SCR for Gas Turbine**	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	**Subtotal for 1 SCR**	4	21	21	0	1	1	1	1	376	72	48,840	9,332
	Subtotal for 2 containment berms					95	37	47	18				
	TOTAL FOR FACILITY 4	**44**	**275**	**146**	**0**	**128**	**70**	**62**	**33**	**1,229**	**482**	**170,053**	**117,171**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**YES**	**NO**				

*For Facility 4, a total of 7 SCRs (6 for Boilers/Heaters and 1 for 1 Gas Turbine) could be installed, but peak construction is based on a 1/3rd overlap of 7 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 5	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	**Construction Emissions Summary**	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 Unmitigated (lb/day)**	**PM10 Mitigated (lb/day)**	**PM2.5 Unmitigated (lb/day)**	**PM2.5 Mitigated (lb/day)**	**Total Diesel Fuel Usage (gal/day)**	**Total Gasoline Fuel Usage (gal/day)**	**Total Diesel Fuel Usage (gal/project)**	**Total Gasoline Fuel Usage (gal/project)**
FCCU	**Subtotal for 1 SCR**	10	66	41	0	3	3	2	2	789	371	205,237	96,568
SRU/TGU	**Subtotal for 1 LoTox with WGSs**	36	233	104	0	30	30	12	12	478	339	72,373	98,508
SRU/TGU	**Subtotal for 1 SCR**	10	66	41	0	3	2	2	2	789	371	205,237	96,568
Gas Turbine	**Subtotal for 2 SCR for Gas Turbine**	8	42	42	0	3	3	3	3	751	144	97,680	18,663
Boilers/Heaters	**Subtotal for 2 SCRs**	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 6 containment berms					284	111	142	55				
	TOTAL FOR FACILITY 5	**72**	**449**	**270**	**1**	**326**	**152**	**164**	**78**	**3,559**	**1,368**	**678,207**	**328,970**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

*For Facility 5, a total of 17 SCRs (12 for Boilers/Heaters, 3 for Gas Turbines, 1 for the FCCU, and 1 for a SRU) could be installed, but peak construction is based on a 1/3rd overlap of 6 SCRs and corresponding containment berms at one time. 1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 6	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	**Construction Emissions Summary**	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 Unmitigated (lb/day)**	**PM10 Mitigated (lb/day)**	**PM2.5 Unmitigated (lb/day)**	**PM2.5 Mitigated (lb/day)**	**Total Diesel Fuel Usage (gal/day)**	**Total Gasoline Fuel Usage (gal/day)**	**Total Diesel Fuel Usage (gal/project)**	**Total Gasoline Fuel Usage (gal/project)**
FCCU	**Subtotal for 1 SCR**	10	66	41	0	3	3	2	2	789	371	205,237	96,568
SRU/TGU	**Subtotal for 1 LoTox with WGSs**	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Gas Turbine	**Subtotal for 1 SCR for Gas Turbine**	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	**Subtotal for 4 SCRs**	16	83	84	0	6	6	5	5	1,503	287	195,360	37,326
	Subtotal for 6 containment berms					284	111	142	55				
	TOTAL FOR FACILITY 6	**66**	**404**	**250**	**1**	**324**	**151**	**163**	**77**	**3,145**	**1,069**	**521,810**	**241,733**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

*For Facility 6, a total of 17 SCRs (15 for Boilers/Heaters, 1 for Gas Turbines, and 1 for the FCCU) could be installed, but peak construction is based on a 1/3rd overlap of 6 SCRs and corresponding containment berms at one time. 1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 7	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
FCCU	Subtotal for 1 ozone generator for LoTox	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Gas Turbine	Subtotal for 1 SCR for Gas Turbine	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	Subtotal for 2 SCRs	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 3 containment berms					142	55	71	28				
	TOTAL FOR FACILITY 7	**16**	**83**	**84**	**0**	**148**	**61**	**76**	**33**	**1,503**	**287**	**195,360**	**37,326**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**YES**	**NO**				

*For Facility 7, a total of 10 SCRs (9 for Boilers/Heaters and 1 for a Gas Turbine) could be installed, but peak construction is based on a 1/3rd overlap of 10 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 8	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
SRU/TGU	Subtotal for 1 LoTox with WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Boilers/Heaters*	Subtotal for 3 SCRs	12	63	63	0	4	4	4	4	1,127	215	146,520	27,995
	Subtotal for 3 containment berms					142	55	71	28				
	TOTAL FOR FACILITY 8	**48**	**296**	**167**	**0**	**177**	**90**	**87**	**44**	**1,605**	**554**	**218,893**	**126,502**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**NO**				

*For Facility 8, a total of 9 SCRs forBoilers/Heaters could be installed, but peak construction is based on a 1/3rd overlap of 9 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 9	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
FCCU	Subtotal for 1 LoTox with WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Boilers/Heaters*	Subtotal for 2 SCRs	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 3 containment berms					142	55	71	28				
	TOTAL FOR FACILITY 9	**44**	**275**	**146**	**0**	**175**	**89**	**86**	**42**	**1,229**	**482**	**170,053**	**117,171**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**NO**				

*For Facility 9, a total of 7 SCRs forBoilers/Heaters could be installed, but peak construction is based on a 1/3rd overlap of 7 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

CONSTRUCTION EMISSIONS AND FUEL USE BY FACILITY

IF ALL CONSTRUCTION OCCURS DURING SAME YEAR	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
TOTAL FOR FACILITY 1	56	338	209	0.41	274	130	137	65	2,356	697	316,573	145,165
TOTAL FOR FACILITY 2	36	233	104	0.20	30	30	12	12	478	339	72,373	98,508
TOTAL FOR FACILITY 3	8	42	42	0.08	98	40	50	21	751	144	97,680	18,663
TOTAL FOR FACILITY 4	44	275	146	0.28	128	70	62	33	1,229	482	170,053	117,171
TOTAL FOR FACILITY 5	72	449	270	0.65	326	152	164	78	3,559	1,368	678,207	328,970
TOTAL FOR FACILITY 6	66	404	250	0.55	324	151	163	77	3,145	1,069	521,810	241,733
TOTAL FOR FACILITY 7	16	83	84	0.17	148	61	76	33	1,503	287	195,360	37,326
TOTAL FOR FACILITY 8	48	296	167	0.33	177	90	87	44	1,605	554	218,893	126,502
TOTAL FOR FACILITY 9	44	275	146	0.28	175	89	86	42	1,229	482	170,053	117,171
GRAND TOTAL	**389**	**2,396**	**1,417**	**2.97**	**1,680**	**814**	**838**	**405**	**15,855**	**5,422**	**2,441,003**	**1,231,208**
Significant Threshold	75	550	100	150	150	150	55	55				
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

IF ALL CONSTRUCTION OCCURS OVER A PERIOD OF 5 YEARS (e.g., 2016 to 2020)	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
TOTAL FOR FACILITY 1	56	338	209	0.41	274	130	137	65	2,356	697	316,573	145,165
TOTAL FOR FACILITY 2	36	233	104	0.20	30	30	12	12	478	339	72,373	98,508
TOTAL FOR FACILITY 3	8	42	42	0.08	98	40	50	21	751	144	97,680	18,663
TOTAL FOR FACILITY 4	44	275	146	0.28	128	70	62	33	1,229	482	170,053	117,171
TOTAL FOR FACILITY 5	72	449	270	0.65	326	152	164	78	3,559	1,368	678,207	328,970
TOTAL FOR FACILITY 6	66	404	250	0.55	324	151	163	77	3,145	1,069	521,810	241,733
TOTAL FOR FACILITY 7	16	83	84	0.17	148	61	76	33	1,503	287	195,360	37,326
TOTAL FOR FACILITY 8	48	296	167	0.33	177	90	87	44	1,605	554	218,893	126,502
TOTAL FOR FACILITY 9	44	275	146	0.28	175	89	86	42	1,229	482	170,053	117,171
GRAND TOTAL OVER 5 YEARS	**78**	**479**	**283**	**0.59**	**336**	**163**	**168**	**81**	**3,171**	**1,084**	**488,201**	**246,242**
Significant Threshold	75	550	100	150	150	150	55	55				
Exceed Significance?	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

IF ALL CONSTRUCTION OCCURS OVER A PERIOD OF 7 YEARS (e.g., 2016 to 2022)	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
TOTAL FOR FACILITY 1	56	338	209	0.41	274	130	137	65	2,356	697	316,573	145,165
TOTAL FOR FACILITY 2	36	233	104	0.20	30	30	12	12	478	339	72,373	98,508
TOTAL FOR FACILITY 3	8	42	42	0.08	98	40	50	21	751	144	97,680	18,663
TOTAL FOR FACILITY 4	44	275	146	0.28	128	70	62	33	1,229	482	170,053	117,171
TOTAL FOR FACILITY 5	72	449	270	0.65	326	152	164	78	3,559	1,368	678,207	328,970
TOTAL FOR FACILITY 6	66	404	250	0.55	324	151	163	77	3,145	1,069	521,810	241,733
TOTAL FOR FACILITY 7	16	83	84	0.17	148	61	76	33	1,503	287	195,360	37,326
TOTAL FOR FACILITY 8	48	296	167	0.33	177	90	87	44	1,605	554	218,893	126,502
TOTAL FOR FACILITY 9	44	275	146	0.28	175	89	86	42	1,229	482	170,053	117,171
GRAND TOTAL OVER 7 YEARS	**56**	**342**	**202**	**0.42**	**240**	**116**	**120**	**58**	**2,265**	**775**	**348,715**	**175,887**
Significant Threshold	75	550	100	150	150	150	55	55				
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**				

Construction Water Use

Water Use from hydrotesting storage tank integrity (post-construction/pre-operation):

Refinery ID	plot space (sf) for all control equip	No. of NH3 storage tanks needed	Capacity of Storage Tank (gal)	Plot space (sf) needed per storage tank	Plot space (sf) needed for all storage tanks	Total plot space (sf) for all control equipment & chemical storage	Total acreage disturbed from Construction (acre)	Number of Tanks Overlapping Construction per day (assumes 1/3rd of total number of tanks)	Amount of Water Needed to Hydrotest during Overlap (gal/day)	Amount of Water Needed to Hydrotest for Entire Project (gal/project)
1	6,417	15	11,000	400	6,000	12,417	0.29	5	55,000	165,000
2	1,200	1	11,000	400	400	1,600	0.04	1	11,000	11,000
3	352	2	11,000	400	800	1,152	0.03	1	11,000	22,000
4	2,463	6	11,000	400	2,400	4,863	0.11	2	22,000	66,000
5	21,418	17	11,000	400	6,800	28,218	0.65	6	66,000	187,000
6	14,165	17	11,000	400	6,800	20,965	0.48	6	66,000	187,000
7	3,840	10	11,000	400	4,000	7,840	0.18	3	33,000	110,000
8	7,409	9	11,000	400	3,600	11,009	0.25	3	33,000	99,000
9	4,263	7	11,000	400	2,800	7,063	0.16	2	22,000	77,000
		84		**Total**	**33,600**	**95,127**	**2.18**	**29**	**319,000**	**924,000**

Water Use for Dust Suppresion (during construction):

Total Area Disturbed, acre	Area Disturbed, ft2	Depth of Water*, ft	Water Use Area, ft3	Water Use, gal	Number of Waterings per day	Total Daily Water Use, gal
2.18	95,127	0.005	476	3,558	3	**10,674**

*Assumes 1/16 inch depth of water applied per washing

GRAND TOTALS (during Operation)

SRU/TGU System

LoTox with Wet Gas Scrubber

	Facility 1			
Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	2,197,800	kWh	6,021	kWh
Water	25.55	MMgal	70,000	gal
Wastewater	5.1	MMgal	13,973	gal
Cooling Water	204,940	MMbtu	561	MMbtu
Compressed Air	50	1000 scf	137	scf
Solid Waste Disposal	250	tons	0.68	tons
Soda Ash	95	tons	0.26	tons
Plot Space needed	3,953	sf		
1 Truck Hauling Away Solid Waste[1]	4,000	round trip miles	400	round trip miles
1 Truck Delivering Soda Ash[2]	200	round trip miles	50	round trip miles
No. of Trucks Hauling Away Solid Waste	10	trucks	1	truck
No. of Trucks Delivering Soda Ash	4	trucks	1	truck

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

	Facility 1			
	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	882,205	kWh	2,417	kWh
Plot Space needed	176	sf		
19% Aqueous NH3 usage at 95% control	278,495	lb	763	lb
19% Aqueous NH3 usage at 95% control	36,262	gal	99	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3[3,4]	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

14 SCRs for 14 boilers/heaters

	Facility 1			
14 SCRs for 14 boilers/heaters	Annual Usage for 14 units		Daily Usage for 14 units	
Electricity	12,350,870	kWh	33,838	kWh
Plot Space needed	2,464	sf		
19% Aqueous NH3 usage at 95% control	3,898,930	lb	10,682	lb
19% Aqueous NH3 usage at 95% control	507,673	gal	1,391	gal
No. of Trucks Delivering Aqueous NH3	73	trucks	1	truck
Trucks Delivering Aqueous NH3[3,4]	7,300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	5	trucks	1	truck
Trucks hauling spent catalyst (once every five years per SCR)	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years per SCR)	500	round trip miles	100	round trip miles

*assume that not all 14 scr will be on same five year catalyst replacement schedule

Daily Usage		Daily Usage		
41,307	Kwh	41.31	MWh	Electricity
70,000	gal			Water
13,973	gal			Wastewater
561	MMbtu			Cooling Water
137	scf			Compressed Air
0.68	tons			Solid Waste Disposal
0.26	tons			Soda Ash (Na2CO3)
6,417	sf			Plot Space needed
11,767	lb	1,532	gal	19% Aqueous NH3
400	Daily round trip miles			1 Truck Hauling Away Solid Waste[1]
50	Daily round trip miles			1 Truck Delivering Soda Ash[2]
1	daily trucks			No. of Trucks Hauling Away Solid Waste
1	daily trucks			No. of Trucks Delivering Soda Ash
100	Daily round trip miles			1 Truck Delivering Aqueous Ammonia[3, 4]
1	daily trucks			No. of Trucks Delivering Aqueous Ammonia
100	Daily round trip miles			1 Truck Hauling Away Spent Catalyst
1	daily trucks			No. of Truck Hauling Away Spent Catalyst
100	Daily round trip miles			1 Truck Delivering Fresh Catalyst
1	daily trucks			No. of Trucks Delivering Fresh Catalyst
750	Daily round trip miles			Total Daily Truck Miles
5	Daily trucks			Total No. of Trucks
13,500	Annual round trip miles			Annual Truck Miles
107	Annual trucks			Annual Trucks

Modify existing Gas Turbine SCR with additional catalyst	Facility 1 Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	528,520	kWh	1,448	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	396,025	lb	1,085	lb
19% Aqueous NH3 usage at 95% control	51,566	gal	141	gal
No. of Trucks Delivering Aqueous NH3	8	trucks	1	truck
1 Truck Delivering Aqueous NH3	800	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 10 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
250 tons/yr solid waste x 1 truck/25 tons = 10 trucks/year to haul extra solid waste away for recycling
This facility either sends its solid waste to a Class III landfill for disposal which is 80.64 miles (one-way) away or to a cement plant cement plant outside of the SCAQMD for recycling.
A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[2]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 4 trucks to deliver one year's worth of soda ash.
95 tons/yr soda ash x 1 truck/25 tons = 3.8 trucks/year to deliver soda ash

[3, 4]Assumes delivery of aqueous ammonia to fill one 2,000 gallon tank. It will take an extra 4 trucks to deliver one year's worth of aqueous ammonia for 1 scr.
6,654 gal/yr NH3 x 1 tank/2,000 gal = 3.3 refills via truck/year to deliver aqueous ammonia

However, to fill 14 aqueous ammonia tanks, one delivery truck can hold up to 7,000 gallons. Thus, the annual number of deliveries to supply all 14 tanks would be 29 trucks.
201,206 gal/yr NH3 x 1 truck/7,000 gal = 28.7 trucks/year to deliver aqueous ammonia

Facility 1 already accesses recycled water and will have increased future access to recycled water.

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Heavy-Heavy Duty Trucks	750	13,500	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
TOTAL	**1**	**5**	**13**	**0**	**1**	**1**	**3,156**	**0**	**3,157**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	56810.72	0.91	56,830	26
TOTAL	**56,811**	**1**	**56,830**	**26**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	750	13,500	4.89	153	2,761
				TOTAL	**153**	**2,761**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	41.31	MWh/day	Electricity GHGs	7521.50	0.0000	0.0000	7,522
water - increased use[1]	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
wastewater - increased generation[1]	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.0001	0.0002	19
temporary construction activities[3]	313	MT/year	Construction GHGs in CO2e				313
operational truck trips	25.77	MT/year	Operation GHGs in CO2e				26
						TOTAL CO2e	7,974

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	41.31	MWh/day	Electricity GHGs	7521.50	0.0000	0.00	7,522
water - increased use[2]	0.07	MMgal/day	Water Conveyance GHGs	8.90	0.0001	0.0001	9
wastewater - increased generation[2]	0.01	MMgal/day	Wastewater Processing GHGs	1.78	0.0000	0.0000	2
temporary construction activities[3]	313.30	MT/year	Construction GHGs in CO2e				313
operational truck trips	25.77	MT/year	Operation GHGs in CO2e				26
						TOTAL CO2e	7,871

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 2

Facility 2 - Coke Calciner
Coke Calciner
UltraCat DGS

Utility/Infrastructure	Annual Usage		Daily Usage		Daily Usage	
Electricity	4,241,535	kW	11,621	kW	11.62	MW
Compressed Air	13,350	1000 scf	36,576	scf	25.40	scfm
Solid Waste Disposal	48.4	tons	0.13	tons		
Aqueous Ammonia (NH3 19%)	1,120,000	lbs	3,068	lbs	128	lb/hr
Aqueous Ammonia (NH3 19%)	145,833	gal	400	gal		
Hydrated Lime Ca(OH)2	659	tons	1.81	tons		
Plot Space Needed	371.25	sf				
1 Truck Hauling Away Solid Waste[1]	800	round trip miles	400	round trip miles		
No. of Trucks Hauling Away Solid Waste	2	trucks	1	truck		
1 Truck Delivering NH3 aq[2]	200	round trip miles	100	round trip miles		
No. of Trucks Delivering NH3aq	21	trucks	1	truck		
1 Truck Delivering Hydrated Lime[2]	1,745	round trip miles	66.20	round trip miles		
No. of Trucks Delivering Hydrated Lime	26	trucks	1	truck		
Total Truck Miles	2745	round trip miles	501	round trip miles		
Total No. of Trucks	49	trucks	3	trucks		

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 2 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
48.4 tons/yr solid waste x 1 truck/25 tons = 1.9 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

Facility 2 - Coke Calciner
Belco wet gas scrubber

Utility/Infrastructure	Annual Usage		Daily Usage		Daily Usage			
Electricity	3,679,200	kWh	17,711	kWh	17.71	MWh	Note: This calculation takes into account the electricity needed to make 3.37 tons per day of NaOH to satisfy demand (7,631 kWh/day).	
Water	14.93	MMgal	40,896	gal	0.04	Mmgal		
Wastewater	6.2	MMgal	16,992	gal	0.02	Mmgal		
Solid Waste Disposal	160	tons	0.44	tons				
NaOH (50%)	1,228	tons	3.37	tons	22	gal/hr	280	lb/hr
Plot Space Needed	1,200	sf			density = 12.747 lb/gal for NaOH at 50%			
1 Truck Hauling Away Solid Waste[2]	2,800	round trip miles	400	round trip miles				
1 Truck Delivering NaOH[3]	1,600	round trip miles	50	round trip miles				
No. of Trucks Hauling Away Solid Waste	7	trucks	1	truck				
No. of Trucks Delivering NaOH	32	trucks	1	truck				
Total Truck Miles	4,400	round trip miles	450	round trip miles				
Total No. of Trucks	39	trucks	2	trucks				

[2]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 7 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
160 tons/yr solid waste x 1 truck/25 tons = 6.4 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[3]Assumes that one 10,000 gallon capacity storage tank will be installed for NaOH storage. It will take 32 trucks to deliver one year's worth of NaOH 50% solution, but the peak would be one truck per day.
1,228 tons/yr NaOH x 2,000 lbs/ ton = 854,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 192,326 gal/year x 1 truck/6,000 gallons = 32 trucks/year

FACILITY 2

GRAND TOTALS (during Operation)
Note: Since this facility has the option to choose between a WGS or DGS, the peak usage is chosen for the grand totals.

Daily Usage		Daily Usage		
11,621	Kwh	11.62	MWh	Electricity
40,896	gal			Water
16,992	gal			Wastewater
36,576	scf			Compressed Air
0.44	tons			Solid Waste Disposal
3,068	lb	400	gal	19% Aqueous NH3
1.81	tons			Hydrated Lime Ca(OH)2
3.37	tons			NaOH
1,200	sf			Plot Space needed
400	Daily round trip miles			1 Truck Hauling Away Solid Waste
66	Daily round trip miles			1 Truck Delivering Hydrated Lime
50	Daily round trip miles			1 Truck Delivering NaOH
100	Daily round trip miles			1 Truck Delivering Aqueous Ammonia
1	daily trucks			No. of Trucks Hauling Away Solid Waste
1	daily trucks			No. of Trucks Delivering Hydrated Lime
1	daily trucks			No. of Trucks Delivering NaOH
1	daily trucks			No. of Trucks Delivering Aqueous Ammonia
2,800	Annual round trip miles			Annual Distance of Trucks Hauling Away Solid Waste
1,745	Annual round trip miles			Annual Distance of Delivering Hydrated Lime
1,600	Annual round trip miles			Annual Distance of Delivering NaOH
200	Annual round trip miles			Annual Distance of Delivering Aqueous Ammonia
7	Annual trucks			No. of Trucks Hauling Away Solid Waste
26	Annual trucks			No. of Trucks Delivering Hydrated Lime
32	Annual trucks			No. of Trucks Delivering NaOH
21	Annual trucks			No. of Trucks Delivering Aqueous Ammonia
616	Daily round trip miles			Total Daily Truck Miles
4	Daily trucks			Total No. of Trucks
6,345	Annual round trip miles			Annual Truck Miles
86	Annual trucks			Annual Trucks

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	Distance (miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	616.20	6,345	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.89	4.01	10.42	0.02	0.52	0.43	2593.09	0.04	2,594
TOTAL	**1**	**4**	**10**	**0**	**1**	**0**	**2,593**	**0**	**2,594**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	26701.17	0.43	26,710	12
TOTAL	**26,701**	**0**	**26,710**	**12**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

FACILITY 2

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	616	6,345	4.89	126	1,298
				TOTAL	126	1,298

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	11.62	MWh/day	Electricity GHGs	2115.96	0.0000	0.0000	2,116
water - increased use[1]	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.0003	0.0006	55
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.0001	0.0002	23
temporary construction activities[3]	82	MT/year	Construction GHGs in CO2e				82
operational truck trips	12.11	MT/year	Operation GHGs in CO2e				12
						TOTAL CO2e	2,288

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2,116
water - increased use[2]	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.00	0.00	55.13
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	22.91
temporary construction activities[3]	81.67	MT/year	Construction GHGs in CO2e				82
operational truck trips	12.11	MT/year	Operation GHGs in CO2e				12
						TOTAL CO2e	2,288

Note: This facility does not have current access or future access to recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 2

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	616	6,345	4.89	126	1,298
				TOTAL	**126**	**1,298**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	11.62	MWh/day	Electricity GHGs	2115.96	0.0000	0.0000	2,116
water - increased use[1]	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.0003	0.0006	55
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.0001	0.0002	23
temporary construction activities[3]	82	MT/year	Construction GHGs in CO2e				82
operational truck trips	12.11	MT/year	Operation GHGs in CO2e				12
						TOTAL CO2e	**2,288**

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2,116
water - increased use[2]	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.00	0.00	55.13
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	22.91
temporary construction activities[3]	81.67	MT/year	Construction GHGs in CO2e				82
operational truck trips	12.11	MT/year	Operation GHGs in CO2e				12
						TOTAL CO2e	**2,288**

Note: This facility does not have current access or future access to recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 3

GRAND TOTALS (during Operation)

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Facility 3 Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	297,110	kWh	814	kWh
Plot Space needed	176	sf		
19% Aqueous NH3 usage at 95% control	234,695	lb	643	lb
19% Aqueous NH3 usage at 95% control	30,559	gal	84	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

Daily Usage		Daily Usage		
1,628	Kwh	1.63	MWh	Electricity
176	sf			Plot Space needed
1,286	lb	167	gal	19% Aqueous NH3 usage at 95% control
352	sf	Plot Space Needed		
1	truck			No. of Trucks Delivering Aqueous NH3
100	Daily round trip miles			1 Truck Delivering Aqueous NH3[1,2]
1	truck			No. of Trucks Hauling Spent Catalyst
100	Daily round trip miles			1 Truck hauling spent catalyst (once every five years)
1	truck			No. of Trucks Delivering Fresh Catalyst
100	Daily round trip miles			1 Truck delivering fresh catalyst (once every five years)
300	Daily round trip miles			Total Daily Truck Miles
3	Daily trucks			Total No. of Trucks
1,100	Annual round trip miles			Annual Truck Miles
11	Annual trucks			Annual Trucks

2 SCR for 2 boilers/heaters

Utility/Infrastructure	Facility 3 Annual Usage for 2 units		Daily Usage for 2 units	
Electricity	594,220	kWh	1,628	kWh
Plot Space needed	352	sf		
19% Aqueous NH3 usage at 95% control	469,390	lb	1,286	lb
19% Aqueous NH3 usage at 95% control	61,118	gal	167	gal
1 Truck Delivering Aqueous NH3[1,2]	9	trucks	1	truck
1 Truck Delivering Aqueous NH3	900	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 9 trucks to deliver one year's worth of aqueous ammonia.
One delivery truck can hold up to 7,000 gallons.
61,118 gal/yr NH3 x 1 truck/7,000 gal = 8.7 trucks/year to deliver aqueous ammonia

FACILITY 3

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance (miles/day)	Annual Round-trip Distance (miles/year)	Mileage Rate (miles/ gallon)	2016 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Heavy-Heavy Duty Trucks	300	1,100	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.44	1.95	5.07	0.01	0.25	0.21	1262.46	0.02	1,263
TOTAL	0	2	5	0	0	0	1,262	0	1,263
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	NO	NO	NO	NO	NO	NO	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	4629.02	0.07	4,631	2
TOTAL	4,629	0	4,631	2
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	300	1,100	4.89	61	225
				TOTAL	61	225

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.63	MWh/day	Electricity GHGs	296.44	0.0000	0.0000	296
temporary construction activities[3]	31	MT/year	Construction GHGs in CO2e				31
operational truck trips	2.10	MT/year	Operation GHGs in CO2e				2
						TOTAL CO2e	329

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.63	MWh/day	Electricity GHGs	296.44	0.0000	0.00	296
temporary construction activities[3]	30.88	MT/year	Construction GHGs in CO2e				31
operational truck trips	2.10	MT/year	Operation GHGs in CO2e				2
						TOTAL CO2e	329

FACILITY 3

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Facility 4

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	297,110	kWh	814	kWh
Plot Space needed	148	sf		
19% Aqueous NH3 usage at 95% control	234,695	lb	643	lb
19% Aqueous NH3 usage at 95% control	30,559	gal	84	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

6 SCR for 6 boilers/heaters

Facility 4

Utility/Infrastructure	Annual Usage for 6 units		Daily Usage for 6 units	
Electricity	1,782,660	kWh	4,884	kWh
Plot Space needed	888	sf		
19% Aqueous NH3 usage at 95% control	1,408,170	lb	3,858	lb
19% Aqueous NH3 usage at 95% control	183,355	gal	502	gal
No. of Trucks Delivering Aqueous NH3	26	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	2,600	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	6	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	600	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	6	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	600	round trip miles	100	round trip miles

FCCU LoTox Wet Gas Scrubber

Facility 4

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	6,887,000	kWh	18,868	kWh
Water	18	MMgal	49,315	gal
Wastewater	8	MMgal	21,918	gal
Cooling Water	240	MMbtu	0.66	MMbtu
Compressed Air	280	1000 scf	767	scf
Solid Waste Disposal	160	tons	0.44	tons
NaOH (50%)	164	tons	0.45	tons
Plot Space Needed	1,575	sf		
1 Truck Hauling Away Solid Waste[3]	2,800	round trip miles	400	round trip miles
1 Truck Delivering NaOH[4]	250	round trip miles	50	round trip miles
No. of Trucks Hauling Away Solid Waste	7	trucks	1	truck
No. of Trucks Delivering NaOH	5	trucks	1	truck

GRAND TOTALS (during Operation)

Daily Usage			Daily Usage	
25,162	kWh	Electricity	25.16	MWh
49,315	gal	Water	0.05	Mmgal
21,918	gal	Wastewater	0.02	Mmgal
0.66	MMbtu	Cooling Water		
767	scf	Compressed Air		
0.44	tons	Solid Waste Disposal		
0.45	tons	NaOH (50%)		
4,249	lb	19% Aqueous NH3 usage at 95% control	553.26	gal
2,463	sf	Plot Space Needed		
400	Daily round trip miles	1 Truck Hauling Away Solid Waste		
50	Daily round trip miles	1 Truck Delivering NaOH		
1	daily trucks	No. of Trucks Hauling Away Solid Waste		
1	daily trucks	No. of Trucks Delivering NaOH		
1	daily trucks	No. of Trucks Delivering Aqueous NH3		
100	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]		
1	daily trucks	No. of Trucks Hauling Spent Catalyst		
100	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)		
1	daily trucks	No. of Trucks Delivering Fresh Catalyst		
100	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)		
750	Daily round trip miles	Total Daily Truck Miles		
5	Daily trucks	Total No. of Trucks		
7,350	Annual round trip miles	Annual Truck Miles		
55	Annual trucks	Annual Trucks		

Note: This calculation takes into account the electricity needed to make 0.45 ton per day of NaOH to satisfy demand (1,019 kWh/day).

Modify 1 existing Gas Turbine SCR	Facility 4			
with additional catalyst	**Annual Usage for 1 unit**		**Daily Usage for 1 unit**	
Electricity	142,715	kWh	391	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	142,715	lb	391	lb
19% Aqueous NH3 usage at 95% control	18,583	gal	51	gal
No. of Trucks Delivering Aqueous NH3	3	trucks	1	truck
1 Truck Delivering Aqueous NH3	300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 5 trucks to deliver one year's worth of aqueous ammonia for one tank

To fill 6 aqueous ammonia tanks, one delivery truck can hold up to 7,000 gallons. Thus, the annual number of deliveries to supply all 6 tanks would be 26 trucks.

183,355 gal/yr NH3 x 1 truck/7,000 gal = 26.2 trucks/year to deliver aqueous ammonia

[3]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 7 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
160 tons/yr solid waste x 1 truck/25 tons = 6.4 trucks/year to haul extra solid waste away for recycling
This facility either sends its solid waste to a cement plant cement plant outside of the SCAQMD for recycling.
A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[4]Assumes that one 10,000 gallon capacity storage tank will be installed for NaOH storage. It will take 5 trucks to deliver one year's worth of NaOH 50% solution, but the peak would be one truck per day.
164 tons/yr NaOH x 2,000 lbs/ ton = 328,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 25,685 gal/year x 1 truck/6,000 gallons = 4.28 trucks/year

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	750	7,350	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
TOTAL	**1**	**5**	**13**	**0**	**1**	**1**	**3,156**	**0**	**3,157**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	30930.28	0.49	30,941	14
TOTAL	**30,930**	**0**	**30,941**	**14**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	750	7,350	4.89	153	1,503
				TOTAL	153	1,503

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	25.16	MWh/day	Electricity GHGs	4581.72	0.0000	0.0000	4,582
water - increased use[1]	0.05	MMgal/day	Water Conveyance GHGs	66.35	0.0004	0.0007	66
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.0002	0.0003	30
temporary construction activities[3]	97	MT/year	Construction GHGs in CO2e				97
operational truck trips	14.03	MT/year	Operation GHGs in CO2e				14
						TOTAL CO2e	4,789

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	25.16	MWh/day	Electricity GHGs	4581.72	0.0000	0.00	4,582
water - increased use[2]	0.05	MMgal/day	Water Conveyance GHGs	66.35	0.00	0.00	66
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
temporary construction activities[3]	97.11	MT/year	Construction GHGs in CO2e				97
operational truck trips	14.03	MT/year	Operation GHGs in CO2e				14
						TOTAL CO2e	4,789

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 5

FCCU + 1SRU/TGU 11,000 aqueous NH3 storage tank + 1 SCR for one SRU/TGU

Utility/Infrastructure	Facility 5 Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	1,300,130	kWh	3,562	kWh
Plot Space needed	4,950	sf		
19% Aqueous NH3 usage at 95% control	1,019,810	lb	2,794	lb
19% Aqueous NH3 usage at 95% control	132,788	gal	363.80	gal
No. of Trucks Delivering Aqueous NH3	19	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	1,897	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

SRU/TGU

2 LoTox with Wet Gas Scrubber

Utility/Infrastructure	Facility 5 Annual Usage for 2 units		Daily Usage for 2 units	
Electricity	4,894,800	kWh	13,410	kWh
Water	80	MMgal	219,178	gal
Wastewater	36	MMgal	98,630	gal
Cooling Water	1,100	MMbtu	3.01	MMbtu
Compressed Air	200	1000 scf	547.95	scf
Solid Waste Disposal	640	tons	1.75	tons
Soda Ash	246	tons	0.67	tons
Plot Space Needed	11,860	sf		
1 Truck Hauling Away Solid Waste[3]	10,400	round trip miles	400	round trip miles
1 Truck Delivering SodaAsh[4]	500	round trip miles	50	round trip miles
No. of Trucks Hauling Away Solid Waste	26	trucks	1	truck
No. of Trucks Delivering Soda Ash	10	trucks	1	truck

FACILITY 5

1 SCR for 1 boiler/heater

with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Facility 5 Annual Usage for 1 unit		Facility 5 Daily Usage for 1 unit		Facility 5 Annual Usage for 12 units		Facility 5 Daily Usage for 12 units	
Electricity	164,615	kWh	451	kWh	1,975,380	kWh	5,412	kWh
Plot Space needed	384	sf			4,608	sf		
19% Aqueous NH3 usage at 95% control	181,040	lb	496	lb	2,172,480	lb	5,952	lb
19% Aqueous NH3 usage at 95% control	23,573	gal	64.58	gal	282,875	gal	775	gal
No. of Trucks Delivering Aqueous NH3	3	trucks	1	truck	40	trucks	1	truck
1 Truck Delivering Aqueous NH3	300	round trip miles	100	round trip miles	4,000	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles

FACILITY 5

Modify 1 existing Gas Turbine SCR with additional catalyst	**Facility 5** Annual Usage for 1 unit		Daily Usage for 1 unit		**Facility 5** Annual Usage for 3 units		Daily Usage for 3 units	
Electricity	285,795	kWh	783	kWh	857,385	kWh	2,349	kWh
Plot Space needed	0	sf			0	sf		
19% Aqueous NH3 usage at 95% control	219,000	lb	600	lb	657,000	lb	1,800	lb
19% Aqueous NH3 usage at 95% control	28,516	gal	78	gal	85,547	gal	234	gal
No. of Trucks Delivering Aqueous NH3	4	trucks	1	truck	12	trucks	1	truck
1 Truck Delivering Aqueous NH3	400	round trip miles	100	round trip miles	1,200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	100	round trip miles	100	round trip miles

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 19 trucks to deliver one year's worth of aqueous ammonia.

One delivery truck can hold up to 7,000 gallons.
132,788 gal/yr NH3 x 1 truck/7,000 gal = 19 trucks/year to deliver aqueous ammonia

[3]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 26 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
640 tons/yr solid waste x 1 truck/25 tons = 25.6 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[4]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 10 trucks to deliver one year's worth of soda ash.
246 tons/yr soda ash x 1 truck/25 tons = 9.84 trucks/year to deliver soda ash

Facility 5 already accesses recycled water.

Facility 5 has two distinct wastewater systems. System One is the un-segregated system, which handles water from cooling towers, boiler blowdowns, and stormwater.
This wastewater receives primary treatment, the maximum capacity for this system is 5000 gpm; the facility is currently running at about 3000 gpm.

System Two is the segregated system, which handles process water. This wastewater receives primary and secondary (biological) treatment.

FACILITY 5

The maximum capacity for this system is 2000 gpm; the facility is currently running at about 1800 gpm.
Facility 5 has some wastewater storage capacity to handle surges due to storms and upsets.

Grand Totals

Daily Usage			Daily Usage	
24,733	kWh	Electricity	24.73	MWh
219,178	gal	Water	0.22	Mmgal
98,630	gal	Wastewater	0.10	Mmgal
3	MMbtu	Cooling Water		
548	scf	Compressed Air		
1.75	tons	Solid Waste Disposal		
0.67	tons	Soda Ash		
21,418	sf	Plot Space Needed		
10,546	lb	19% Aqueous NH3 usage at 95% control	1,373	gal
400	Daily round trip miles	1 Truck Hauling Away Solid Waste		
50	Daily round trip miles	1 Truck Delivering Soda Ash		
1	daily trucks	No. of Trucks Hauling Away Solid Waste		
1	daily trucks	No. of Trucks Delivering Soda Ash		
3	daily trucks	No. of Trucks Delivering Aqueous NH3		
300	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]		
3	daily trucks	No. of Trucks Hauling Spent Catalyst		
300	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)		
3	daily trucks	No. of Trucks Delivering Fresh Catalyst		
300	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)		
1,350	Daily round trip miles	Total Daily Truck Miles		
11	Daily trucks	Total No. of Trucks		
19,397	Annual round trip miles	Annual Truck Miles		
121	Annual trucks	Annual Trucks		

FACILITY 5

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip	Annual Round trip	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	Distance (miles/day)	Distance (miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	1350	19,397	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.96	8.78	22.82	0.05	1.15	0.94	5681.07	0.09	5,683
TOTAL	**2**	**9**	**23**	**0**	**1**	**1**	**5,681**	**0**	**5,683**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	81626.35	1.30	81,654	37
TOTAL	**81,626**	**1**	**81,654**	**37**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	1,350	19,397	4.89	276	3,967
				TOTAL	**276**	**3,967**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	24.73	MWh/day	Electricity GHGs	4503.61	0.0000	0.0000	4,504
water - increased use[1]	0.22	MMgal/day	Water Conveyance GHGs	294.89	0.0017	0.0031	295
wastewater - increased generation[1]	0.10	MMgal/day	Wastewater Processing GHGs	132.70	0.0008	0.0014	133
temporary construction activities[3]	363	MT/year	Construction GHGs in CO2e				363
operational truck trips	37.03	MT/year	Operation GHGs in CO2e				37
						TOTAL CO2e	**5,332**

FACILITY 5

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	24.73	MWh/day	Electricity GHGs	4503.61	0.0000	0.00	4,504
water - increased use[2]	0.22	MMgal/day	Water Conveyance GHGs	27.86	0.0002	0.0003	28
wastewater - increased generation[2]	0.10	MMgal/day	Wastewater Processing GHGs	12.54	0.0001	0.0001	13
temporary construction activities[3]	362.91	MT/year	Construction GHGs in CO2e				363
operational truck trips	37.03	MT/year	Operation GHGs in CO2e				37
						TOTAL CO2e	**4,944**

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 6

FCCU

1 SCR for 1 FCCU with one 11,000 aqueous NH3 storage tank — **Facility 6**

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	456,980	kWh	1,252	kWh
Plot Space needed	2,475	sf		
19% Aqueous NH3 usage at 95% control	509,905	lb	1,397	lb
19% Aqueous NH3 usage at 95% control	66,394	gal	182	gal
No. of Trucks Delivering Aqueous NH3	9	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	948	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

SRU/TGU System

LoTox with Wet Gas Scrubber — **Facility 6**

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	2,447,400	kWh	6,705	kWh
Water	40	MMgal	109,589	gal
Wastewater	18	MMgal	49,315	gal
Cooling Water	550	MMbtu	1.51	MMbtu
Compressed Air	100	1000 scf	274	scf
Solid Waste Disposal	320	tons	0.88	tons
Soda Ash	123	tons	0.34	tons
Plot Space Needed	5,930	sf		
1 Truck Hauling Away Solid Waste[3]	5,200	round trip miles	400	round trip miles
1 Truck Delivering Soda Ash[4]	250	round trip miles	50	round trip miles
No. of Trucks Hauling Away Solid Waste	13	trucks	1	truck
No. of Trucks Delivering Soda Ash	5	trucks	1	truck

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank — **Facility 6**

Utility/Infrastructure	**Annual Usage for 1 unit**		**Daily Usage for 1 unit**		**Annual Usage for 15 units**		**Daily Usage for 15 units**	
Electricity	329,230	kWh	902	kWh	4,938,450	kWh	13,530	kWh
Plot Space needed	384	sf			5,760	sf		
19% Aqueous NH3 usage at 95% control	368,650	lb	1,010	lb	5,529,750	lb	15,150	lb
19% Aqueous NH3 usage at 95% control	48,001	gal	132	gal	720,020	gal	1,973	gal
No. of Trucks Delivering Aqueous NH3	7	trucks	1	truck	103	trucks	1	truck
1 Truck Delivering Aqueous NH3	700	round trip miles	100	round trip miles	10,300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles

Modify 1 existing Gas Turbine SCR with additional catalyst — **Facility 6**

	Annual Usage for 1 unit		**Daily Usage for 1 unit**	
Electricity	142,715	kWh	391	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	109,500	lb	300	lb
19% Aqueous NH3 usage at 95% control	14,258	gal	39	gal
No. of Trucks Delivering Aqueous NH3	2	trucks	1	truck
1 Truck Delivering Aqueous NH3	200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 9 trucks to deliver one year's worth of aqueous ammonia.

One delivery truck can hold up to 7,000 gallons.
66,394 gal/yr NH3 x 1 truck/7,000 gal = 9.4 trucks/year to deliver aqueous ammonia

[3]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 13 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
320 tons/yr solid waste x 1 truck/25 tons = 12.8 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[4]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 5 trucks to deliver one year's worth of soda ash.
123 tons/yr soda ash x 1 truck/25 tons = 4.92 trucks/year to deliver soda ash

Facility 6 can buy recycled water from California Water Service Company.

FACILITY 6

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage		
21,878	Kwh	21.88	MWh	Electricity
109,589	gal	0.109589041	Mmgal	Water
49,315	gal	0.049315068	Mmgal	Wastewater
1.51	MMbtu			Cooling Water
274	scf			Compressed Air
0.88	tons			Solid Waste Disposal
0.34	tons			soda ash
14,165	sf			Plot Space needed

16,847	lb	19% Aqueous NH3 usage at 95% control	2,194	gal
400	Daily round trip miles	1 Truck Hauling Away Solid Waste[3]		
50	Daily round trip miles	1 Truck Delivering Soda Ash[4]		
1	daily trucks	No. of Trucks Hauling Away Solid Waste		
1	daily trucks	No. of Trucks Delivering Soda Ash		
3	daily trucks	No. of Trucks Delivering Aqueous NH3		
300	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]		
3	daily trucks	No. of Trucks Hauling Spent Catalyst		
300	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)		
3	daily trucks	No. of Trucks Delivering Fresh Catalyst		
300	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)		
1,350	Daily round trip miles	Total Daily Truck Miles		
11	Daily trucks	Total No. of Trucks		
18,298	Annual round trip miles	Annual Truck Miles		
146	Annual trucks	Annual Trucks		

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance (miles/day)	Annual Round-trip Distance (miles/year)	Mileage Rate (miles/ gallon)	2016 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	1350	18,298	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.96	8.78	22.82	0.05	1.15	0.94	5681.07	0.09	5,683
TOTAL	**2**	**9**	**23**	**0**	**1**	**1**	**5,681**	**0**	**5,683**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

FACILITY 6

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	77003.70	1.23	77,030	35
TOTAL	**77,004**	**1**	**77,030**	**35**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	1350	18,298	4.89	276	3,742

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	21.88	MWh/day	Electricity GHGs	3983.72	0.0000	0.0000	3,984
water - increased use[1]	0.11	MMgal/day	Water Conveyance GHGs	147.45	0.0009	0.0015	148
wastewater - increased generation[1]	0.05	MMgal/day	Wastewater Processing GHGs	66.35	0.0004	0.0007	66
temporary construction activities[3]	181	MT/year	Construction GHGs in CO2e				181
operational truck trips	34.93	MT/year	Operation GHGs in CO2e				35
						TOTAL CO2e	**4,414**

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	21.88	MWh/day	Electricity GHGs	3983.72	0.0000	0.00	3,984
water - increased use[2]	0.11	MMgal/day	Water Conveyance GHGs	13.93	0.0001	0.0001	14
wastewater - increased generation[2]	0.05	MMgal/day	Wastewater Processing GHGs	6.27	0.0000	0.0001	6
temporary construction activities[3]	181.46	MT/year	Construction GHGs in CO2e				181
operational truck trips	34.93	MT/year	Operation GHGs in CO2e				35
						TOTAL CO2e	**4,220**

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

FACILITY 6

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 7

Modify 1 existing Gas Turbine SCR with additional catalyst — Facility 7

with additional catalyst	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	428,510	kWh	1,174	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	281,415	lb	771	lb
19% Aqueous NH3 usage at 95% control	36,643	gal	100	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Facility 7 Annual Usage for 1 unit		Facility 7 Daily Usage for 1 unit		Facility 7 Annual Usage for 9 units		Facility 7 Daily Usage for 9 units	
Electricity	243,090	kWh	666	kWh	2,187,810	kWh	5,994	kWh
Plot Space needed	384	sf			3,456	sf		
19% Aqueous NH3 usage at 95% control	271,925	lb	745	lb	2,447,325	lb	6,705	lb
19% Aqueous NH3 usage at 95% control	35,407	gal	97.01	gal	318,662	gal	873	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck	46	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	500	round trip miles	100	round trip miles	4,600	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles

FCCU: 1LoTox Ozone Generator for existing WGS — Facility 7

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit		
Electricity	365,000	kWh	1,000	kWh	
Plot Space needed	384	sf			
Oxygen (in pounds)	2,901,750	lb	7,950	lb	9.527 lbs O2 for 1 gallon
Oxygen (in gallons)	304,582	gal	834	gal	
No. of Trucks Delivering Oxygen	44	trucks	1	truck	
1 Truck Delivering Oxygen	2,176	round trip miles	50	round trip miles	

FACILITY 7

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage				
8,168	Kwh	8.17	MWh	Electricity		
7,950	lb	oxygen				
7,476	lb	19% Aqueous NH3 usage at 95% control			973	gal
3,840	sf		Plot Space needed			
2	daily trucks		No. of Trucks Delivering Aqueous NH3			
200	Daily round trip miles		1 Truck Delivering Aqueous NH3[1,2]			
2	daily trucks		No. of Trucks Hauling Spent Catalyst			
200	Daily round trip miles		1 Truck hauling spent catalyst (once every five years)			
2	daily trucks		No. of Trucks Delivering Fresh Catalyst			
200	Daily round trip miles		1 Truck delivering fresh catalyst (once every five years)			
1	daily trucks		No. of Trucks Delivering Oxygen			
50	Daily round trip miles		1 Truck delivering Oxygen			
650	Daily round trip miles		Total Daily Truck Miles			
5	Daily trucks		Total No. of Trucks			
8,476	Annual round trip miles		Annual Truck Miles			
107	Annual trucks		Annual Trucks			

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 51 trucks to deliver one year's worth of aqueous ammonia.

One delivery truck can hold up to 7,000 gallons.
355,305 gal/yr NH3 x 1 truck/7,000 gal = 51 trucks/year to deliver aqueous ammonia

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	650	8,476	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.94	4.23	10.99	0.03	0.55	0.45	2735.33	0.04	2,736
TOTAL	1	4	11	0	1	0	2,735	0	2,736
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	NO	NO	NO	NO	NO	NO	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	35666.96	0.57	35,679	16
TOTAL	35,667	1	35,679	16
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	650	8,476	4.89	133	1,733
				TOTAL	133	1,733

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

FACILITY 7

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	8.17	MWh/day	Electricity GHGs	1487.28	0.0000	0.0000	1,487
temporary construction activities[3]	85	MT/year	Construction GHGs in CO2e				85
operational truck trips	16.18	MT/year	Operation GHGs in CO2e				16
						TOTAL CO2e	1,588

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	8.17	MWh/day	Electricity GHGs	1487.28	0.0000	0.00	1,487
temporary construction activities[3]	84.93	MT/year	Construction GHGs in CO2e				85
operational truck trips	16.18	MT/year	Operation GHGs in CO2e				16
						TOTAL CO2e	1,588

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FACILITY 8

SRU/TGU System

LoTox with Wet Gas Scrubber

Utility/Infrastructure	Annual Usage		Facility 8 Daily Usage		Daily Usage	
Electricity	1,809,000	kWh	4,956	kWh	4.96	MWh
Water	25.55	MMgal	70,000	gal	0.07	Mmgal
Wastewater	5.1	MMgal	13,973	gal	0.01	Mmgal
Cooling Water	168,700	MMbtu	462	MMbtu		
Compressed Air	100	1000 scf	274	scf		
Solid Waste Disposal	120	tons	0.33	tons		
Soda Ash	45	tons	0.12	tons		
plot space needed	3,953	sf				
1 Truck Hauling Away Solid Waste[1]	2,000	round trip miles	400	round trip miles		
1 Truck Delivering Soda Ash[2]	100	round trip miles	50	round trip miles		
No. of Trucks Hauling Away Solid Waste	5	trucks	1	truck		
No. of Trucks Delivering Soda Ash	2	trucks	1	truck		

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Facility 8 Annual Usage for 1 unit		Daily Usage for 1 unit		Facility 8 Annual Usage for 9 units		Daily Usage for 9 units	
Electricity	379,235	kWh	1,039	kWh	3,413,115	kWh	9,351	kWh
Plot Space needed	384	sf			3,456	sf		
19% Aqueous NH3 usage at 95% control	424,495	lb	1,163	lb	3,820,455	lb	10,467	lb
19% Aqueous NH3 usage at 95% control	55,273	gal	151.43	gal	497,455	gal	1,363	gal
No. of Trucks Delivering Aqueous NH3	8	trucks	1	truck	71	trucks	1	truck
1 Truck Delivering Aqueous NH3[3,4]	790	round trip miles	100	round trip miles	7,100	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 30 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
120 tons/yr solid waste x 1 truck/25 tons = 4.8 trucks/year to haul extra solid waste away for recycling

[2]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 2 trucks to deliver one year's worth of soda ash.
45 tons/yr soda ash x 1 truck/25 tons = 1.8 trucks/year to deliver soda ash

[3,4] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 8 trucks to deliver one year's worth of aqueous ammonia.
One delivery truck can hold up to 7,000 gallons.
55,273 gal/yr NH3 x 1 truck/7,000 gal = 7.9 trucks/year to deliver aqueous ammonia

It is not known at this time if Facility 8 will have future access to recycled water. Facility 8 currently uses non-potable well water to supply the facility.

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage				
14,307	Kwh	14.31	MWh	Electricity		
70,000	gal	0.07	MMgal	Water		
13,973	gal	0.01	MMgal	Wastewater		
462	MMbtu			Cooling Water		
274	scf			Compressed Air		
0.33	tons			Solid Waste Disposal		
0.12	tons			Soda Ash		
10,467	lb	19% Aqueous NH3 usage at 95% control			1,363	gal
7,409	sf		Plot Space needed			
400	Daily round trip miles		1 Truck Hauling Away Solid Waste[1]			
50	Daily round trip miles		1 Truck Delivering Soda Ash[2]			
1	daily trucks		No. of Trucks Hauling Away Solid Waste			
1	daily trucks		No. of Trucks Delivering Soda Ash			
1	daily trucks		No. of Trucks Delivering Aqueous NH3			
100	Daily round trip miles		1 Truck Delivering Aqueous NH3[3,4]			
1	daily trucks		No. of Trucks Hauling Spent Catalyst			
100	Daily round trip miles		1 Truck hauling spent catalyst (once every five years)			
1	daily trucks		No. of Trucks Delivering Fresh Catalyst			
100	Daily round trip miles		1 Truck delivering fresh catalyst (once every five years)			
750	Daily round trip miles		Total Daily Truck Miles			
5	Daily trucks		Total No. of Trucks			
10,200	Annual round trip miles		Annual Truck Miles			
88	Annual trucks		Annual Trucks			

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip	Annual Round-trip	Mileage Rate	2016 Mobile Source Emission Factors								
On-Road Equipment Type	Distance (miles/day)	Distance (miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	750	10,200	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
TOTAL	**1**	**5**	**13**	**0**	**1**	**1**	**3,156**	**0**	**3,157**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	42923.65	0.69	42,938	19
TOTAL	**42,924**	**1**	**42,938**	**19**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	750	10,200	4.89	153	2,086
Source:				**TOTAL**	**153**	**2,086**

On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016

http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	14.31	MWh/day	Electricity GHGs	2605.14	0.0000	0.0000	2,605
water - increased use[1]	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
wastewater - increased generation[1]	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.0001	0.0002	19
temporary construction activities[3]	151	MT/year	Construction GHGs in CO2e				151
operational truck trips	19.47	MT/year	Operation GHGs in CO2e				19
						TOTAL CO2e	**2,889**

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	14.31	MWh/day	Electricity GHGs	2605.14	0.0000	0.00	2,605
water - increased use[2]	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.00	0.00	94
wastewater - increased generation[2]	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	19
temporary construction activities[3]	151.16	MT/year	Construction GHGs in CO2e				151
operational truck trips	19.47	MT/year	Operation GHGs in CO2e				19
						TOTAL CO2e	**2,889**

FACILITY 8

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FCCU

LoTox with Wet Gas Scrubber

Utility/Infrastructure	Annual Usage		Facility 9 Daily Usage	
Electricity	5,789,000	kWh	15,860	kWh
Water	16	MMgal	43,836	gal
Wastewater	8	MMgal	21,918	gal
Cooling Water	200	MMbtu	0.55	MMbtu
Compressed Air	260	1000 scf	712	scf
Solid Waste Disposal	690	tons	1.89	tons
NaOH (50%)	738	tons	2.02	tons
Plot Space needed	1,575	sf		
1 Truck Hauling Away Solid Waste[1]	11,200	round trip miles	400	round trip miles
1 Truck Delivering NaOH[2]	950	round trip miles	50	round trip miles
No. of Trucks Hauling Away Solid Waste	28	trucks	1	truck
No. of Trucks Delivering NaOH	19	trucks	1	truck

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Facility 9 Annual Usage for 1 unit		Daily Usage for 1 unit		Facility 9 Annual Usage for 7 units		Daily Usage for 7 units	
Electricity	195,640	kWh	536	kWh	1,369,480	kWh	3,752	kWh
Plot Space needed	384	sf			2,688	sf		
19% Aqueous NH3 usage at 95% control	219,365	lb	601	lb	1,535,555	lb	4,207	lb
19% Aqueous NH3 usage at 95% control	28,563	gal	78	gal	199,942	gal	548	gal
No. of Trucks Delivering Aqueous NH3	4	trucks	1	truck	29	trucks	1	truck
1 Truck Delivering Aqueous NH3[3, 4]	400	round trip miles	100	round trip miles	2,900	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	9	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	900	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	9	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	900	round trip miles	100	round trip miles

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 28 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
690 tons/yr solid waste x 1 truck/25 tons = 27.6 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[2]Assumes that one 10,000 gallon capacity storage tank will be installed for NaOH storage. It will take 19 trucks to deliver one year's worth of NaOH 50% solution, but the peak would be one truck per day.

738 tons/yr NaOH x 2,000 lbs/ ton = 1,476,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 115,583 gal/year x 1 truck/6,000 gallons = 19.2 trucks/year

[3,4] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 29 trucks to deliver one year's worth of aqueous ammonia.
One delivery truck can hold up to 7,000 gallons.
199,942 gal/yr NH3 x 1 truck/7,000 gal = 28.6 trucks/year to deliver aqueous ammonia

Facility 9 may have future access to recycled water.

GRAND TOTALS (during Operation)

Note: This calculation takes into account the electricity needed to make 2.02 tons per day of NaOH to satisfy demand (4,585 kWh/day).

Daily Usage		Daily Usage			
20,445	Kwh	20.45	MWh	Electricity	
43,836	gal	0.04	Mmgal	Water	
21,918	gal	0.02	Mmgal	Wastewater	
0.55	MMbtu			Cooling Water	
712	scf			Compressed Air	
1.89	tons			Solid Waste Disposal	
2.02	tons			NaOH (50% by weight)	
4,263	sf			Plot Space needed	
4,207	lb	19% Aqueous NH3 usage at 95% control		548	gal
400	Daily round trip miles			1 Truck Hauling Away Solid Waste[1]	
1	daily trucks			No. of Trucks Hauling Away Solid Waste	
50	Daily round trip miles			1 Truck Delivering NaOH[2]	
1	daily trucks			No. of Trucks Delivering NaOH	
1	daily trucks			No. of Trucks Delivering Aqueous NH3	
100	Daily round trip miles			1 Truck Delivering Aqueous NH3[3, 4]	
1	daily trucks			No. of Trucks Hauling Spent Catalyst	
100	Daily round trip miles			1 Truck hauling spent catalyst (once every five years)	
1	daily trucks			No. of Trucks Delivering Fresh Catalyst	
100	Daily round trip miles			1 Truck delivering fresh catalyst (once every five years)	
750	Daily round trip miles			Total Daily Truck Miles	
5	Daily trucks			Total No. of Trucks	
16,850	Annual round trip miles			Annual Truck Miles	
94	Annual trucks			Annual Trucks	

FACILITY 9

Operations - On-Road Vehicles and Fuel Use

Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	750	16,850	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Offsite (Heavy-Heavy Duty Truck)	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
SUBTOTAL	1	5	13	0	1	1	3,156	0	3,157
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	NO	NO	NO	NO	NO	NO	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	70908.19	1.13	70,932	32
TOTAL	70,908	1	70,932	32
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Offsite Delivery/Haul	Heavy Duty Truck	750	16850	4.89	153	3,446
				TOTAL	153	3,446

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	20.45	MWh/day	Electricity GHGs	3722.77	0.0000	0.0000	3,723
water - increased use[1]	0.04	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.0006	59
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.0002	0.0003	30
temporary construction activities[3]	136	MT/year	Construction GHGs in CO2e				136
operational truck trips	32.17	MT/year	Operation GHGs in CO2e				32
						TOTAL CO2e	3,979

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	20.45	MWh/day	Electricity GHGs	3722.77	0.0000	0.00	3,723
water - increased use[2]	0.04	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.00	59
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
temporary construction activities[3]	135.71	MT/year	Construction GHGs in CO2e				136
operational truck trips	32.17	MT/year	Operation GHGs in CO2e				32
						TOTAL CO2e	3,979

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

Solid Waste Handling

Refinery ID	Current Solid Waste Hauled away (tons/day)	Solid Waste is trucked to?	Distance to out of state cement plant for recycling (miles, one-way)	Proposed increase in Solid Waste (ton/day)	Increase in Solid Waste will be trucked to?
1	4.66	cement plant or Class III landfill	200	0.68	cement plant
2	175	cement plant	200	0.44	cement plant
4	0.99	n/a	n/a	0.00	n/a
5	1.12	cement plant	200	1.75	cement plant
6	0.41	cement plant	200	0.88	cement plant
7	2.16	n/a	n/a	0.00	n/a
8	not provided	cement plant	200	0.33	cement plant
9	2	cement plant	200	1.89	cement plant
				5.97	

PROPOSED PROJECT: NaOH LOSSES

Facility ID	NaOH Demand (tons/day)	Q = Fill Rate = NaOH Demand (MMgal/day)	S = Saturation Factor	P = Vapor Pressure of material Loaded (psia)	M = NaOH vapor molecular weight (lb/lbmole)	T= temperature of liquid loaded (°R)	Daily PM10 Filling Loss (lb/day)	$E_{loading}$ = Hourly PM10 Filling Loss (lb/hr)	$E_{working}$ = Hourly PM10 Working Loss (lb/hr)	Total Hourly PM10 Loss (lb/hr)	Acute Screening Level - 25 meters (lb/hr)	Does Hourly Filling Loss Exceed Acute Screening Level? (Yes/No)	Significant?	Electricity Needed to Produce NaOH* (kWh/day)
2	3.37	0.53	1.45	0.0420	24.8	544.67	1.82E-02	7.60E-04	2.28E-03	3.04E-03	4.00E-03	NO	NO	7631
4	0.45	0.07	1.45	0.0420	24.8	544.67	2.44E-03	1.01E-04	3.04E-04	4.06E-04	4.00E-03	NO	NO	1019
9	2.02	0.32	1.45	0.0420	24.8	544.67	1.10E-02	4.57E-04	1.37E-03	1.83E-03	4.00E-03	NO	NO	4585
TOTAL	**5.84**	**0.92**					**0.03**							**13,235**

NaOH @ 50% solution density = 12.747 lb/gal
Mv for NaOH solution = 24.8 lb/lbmol
Vapor Pressure for NaOH = 2.18 mmHg at 29.4oC or 85oF = 0.042 psia
Loading Temperature = 85oF to 100oF (544.67oR to 559.67oR)
Breathing Loss = 3 * Filling Loss

Filling Loss:

$$E_{Loading}, {}^{lb}\!/_{day} = (12.46)\frac{(S)(P)(M)(Q)}{T}$$

where:

S = saturation factor (dimensionless; obtained from Table 5.2-1 in AP-42)
= 1.45 (Splash loading: dedicated normal service)
P = vapor pressure of the material loaded at temperature T (psia)
M = vapor molecular weight (lb/lb-mole)
Q = volume of material loaded (1,000 gal/day)
T = temperature of liquid loaded (°R).

*It takes approximately 2,500 kWh to produce one metric ton of NaOH.
Thus, approximately 22,444 kWh per day of additional electricity may be needed to produce additional NaOH to meet the needs of the proposed project, calculated as follows:

$$\frac{9.9 \text{ tons NaOH}}{\text{Day}} \times \frac{2{,}000 \text{ lbs}}{\text{ton}} \times \frac{1 \text{ metric ton}}{2{,}205 \text{ lbs}} \times \frac{2{,}500 \text{ kWh}}{1 \text{ metric ton of NaOH produced}} = 22{,}444 \text{ kWh/day}$$

PROPOSED PROJECT: NaOH LOSSES

Facility ID	NaOH Demand (tons/day)	Q = Fill Rate = NaOH Demand (MMgal/day)	S = Saturation Factor	P = Vapor Pressure of material Loaded (psia)	M = NaOH vapor molecular weight (lb/lbmole)	T= temperature of liquid loaded (°R)	Daily PM10 Filling Loss (lb/day)	$E_{loading}$ = Hourly PM10 Filling Loss (lb/hr)	$E_{working}$ = Hourly PM10 Working Loss (lb/hr)	Total Hourly PM10 Loss (lb/hr)	Acute Screening Level - 25 meters (lb/hr)	Does Hourly Filling Loss Exceed Acute Screening Level? (Yes/No)	Significant?	Electricity Needed to Produce NaOH* (kWh/day)
2	3.37	0.53	1.45	0.0420	24.8	544.67	1.82E-02	7.60E-04	2.28E-03	3.04E-03	4.00E-03	NO	NO	7631
4	0.45	0.07	1.45	0.0420	24.8	544.67	2.44E-03	1.01E-04	3.04E-04	4.06E-04	4.00E-03	NO	NO	1019
9	2.02	0.32	1.45	0.0420	24.8	544.67	1.10E-02	4.57E-04	1.37E-03	1.83E-03	4.00E-03	NO	NO	4585
TOTAL	**5.84**	**0.92**					**0.03**							**13,235**

NaOH @ 50% solution density = 12.747 lb/gal
Mv for NaOH solution = 24.8 lb/lbmol
Vapor Pressure for NaOH = 2.18 mmHg at 29.4oC or 85oF = 0.042 psia
Loading Temperature = 85oF to 100oF (544.67oR to 559.67oR)
Breathing Loss = 3 * Filling Loss

Filling Loss:

$$E_{Loading}, {}^{lb}\!/_{day} = (12.46)\frac{(S)(P)(M)(Q)}{T}$$ where:

S = saturation factor (dimensionless; obtained from Table 5.2-1 in AP-42)
= 1.45 (Splash loading: dedicated normal service)
P = vapor pressure of the material loaded at temperature T (psia)
M = vapor molecular weight (lb/lb-mole)
Q = volume of material loaded (1,000 gal/day)
T = temperature of liquid loaded (°R).

*It takes approximately 2,500 kWh to produce one metric ton of NaOH.
Thus, approximately 22,444 kWh per day of additional electricity may be needed to produce additional NaOH to meet the needs of the proposed project, calculated as follows:

$$\frac{9.9 \text{ tons NaOH}}{\text{Day}} \times \frac{2{,}000 \text{ lbs}}{\text{ton}} \times \frac{1 \text{ metric ton}}{2{,}205 \text{ lbs}} \times \frac{2{,}500 \text{ kWh}}{1 \text{ metric ton of NaOH produced}} = 22{,}444 \text{ kWh/day}$$

Operation of 1 SCR at a Refinery

Refinery Operation Activities for 1 SCR

Facility Type	No. of SCR	Operation Activity
Affected Facilities with SCR Retrofits	1	Operation/Maintenance of SCR + One Ammonia Tank

Operation Schedule 365 days/yr - 24 hours/day
Catalyst Replacement Schedule: Approximately once every 5 years
Ammonia Delivery Schedule: Two truck deliveries (at 7,000 gallons per truck) per week would be needed to fill one storage tank.

Activity	No. of Facilities receiving deliveries on a peak day	Days of Deliveries	Crew Size per delivery
Supply Deliveries	1	1.00	1

Operation	Fuel	Number Needed	Round- trip Distance (miles/day)	Mileage Rate (miles/gal)	2016 Mobile Source Emission Factors							
On-Road Equipment Type					VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Truck Delivery of Spent Catalyst Modules	diesel	1	100	8.9	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722
Truck Delivery of Fresh Catalyst	diesel	1	100	8.9	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722
Truck Delivery of Aqueous Ammonia	diesel	1	100	8.9	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Combustion Emissions from On-Road Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/ project)
Truck Delivery of Spent Catalyst Modules	0.15	0.65	1.69	0.00	0.08	0.07	420.82	0.01	420.96	0.1909
Truck Delivery of Fresh Catalyst	0.15	0.65	1.69	0.0040	0.0849	0.0697	420.82	0.01	420.96	0.1909
Truck Delivery of Aqueous Ammonia	0.15	0.65	1.69	0.0040	0.0849	0.0697	420.82	0.01	420.96	0.1909
SUBTOTAL	**0.44**	**1.95**	**5.07**	**0.01**	**0.25**	**0.21**	**1262.46**	**0.02**	**1262.88**	**0.57**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Emissions (lb/day)
*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
*1 metric ton (MT) = 2,205 pounds

Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq (lb/day)	CO2eq* (MT/ project)
Emissions from On-Road Vehicles	0.15	0.65	1.69	0.00	0.0849	0.0697	420.82	0.01	420.96	0.1909
TOTAL for 1 Facility	**0**	**1**	**2**	**0**	**0**	**0**	**421**	**0**	**421**	**0**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage Delivery Activities	Equipment Type	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Peak Annual Diesel Fuel Usage (gal/yr)	
Truck Delivery of Spent Catalyst Modules	Heavy Duty Truck	11.24	11.24	This activity would occur once every 5 Years
Truck Delivery of Fresh Catalyst	Heavy Duty Truck	11.24	11.24	This activity would occur once every 5 Years
Truck Delivery of Aqueous Ammonia	Heavy Duty Truck	11.24	1168.54	
TOTAL for 1 Facility		**33.71**	**1,191.01**	

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Construction of 1 SCR for Refinery Boiler, Process Heater, or Gas Turbine

Install 1 SCR for 1 refinery boiler/process heater or refinery gas turbine

Activity	Days/ wk	Hrs/day	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	8	4.33	21.67	6	130.00	20
				Total	6	130.00	

Construction	Max Equipment Rating	Number	Operating Schedule	Usage Factor	2015 Mobile Source Emission Factors							
Off-Road Equipment Type	hp	Needed	(hr/day)		VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2 (lb/hr)	CH4 (lb/hr)
Rough Terrain Crane (28 ton)	120	1	8	1	0.0800	0.3559	0.4822	0.0006	0.0415	0.0382	50.1	0.0072
Welding Machines	Composite	2	8	1	0.0534	0.1994	0.2301	0.0003	0.0187	0.0172	25.6	0.0048
Air Compressor	Composite	1	1	1	0.0773	0.3257	0.5175	0.0007	0.0357	0.0329	63.6	0.0070
Backhoe	Composite	1	4	1	0.0666	0.3716	0.4501	0.0008	0.0298	0.0274	66.8	0.0060
Plate Compactor	Composite	1	4	1	0.0050	0.0263	0.0314	0.0001	0.0012	0.0011	4.3	0.0005
Forklift	Composite	1	3	1	0.0459	0.2200	0.3163	0.0006	0.0156	0.0143	54.4	0.0041
Concrete Pump	Composite	1	2	1	0.0621	0.2825	0.4121	0.0006	0.0267	0.0245	49.6	0.0056
Concrete Saw	Composite	1	2	1	0.0835	0.3982	0.4921	0.0007	0.0374	0.0345	58.5	0.0075
Generator	Composite	1	8	1	0.0640	0.2913	0.4717	0.0007	0.0268	0.0246	61.0	0.0058
Aerial Lift (Man lift)	Composite	1	2	1	0.0439	0.1837	0.2670	0.0004	0.0167	0.0154	34.7	0.0040

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Rough Terrain Crane (28 ton)	0.64	2.85	3.86	0.00	0.33	0.31	401.18	0.06	402.40	0.79
Welding Machines	0.85	3.19	3.68	0.01	0.30	0.27	409.64	0.08	411.26	0.81
Air Compressor	0.08	0.33	0.52	0.00	0.04	0.03	63.61	0.01	63.75	0.13
Backhoe	0.27	1.49	1.80	0.00	0.12	0.11	267.20	0.02	267.70	0.53
Plate Compactor	0.02	0.11	0.13	0.00	0.00	0.00	17.26	0.00	17.29	0.03
Forklift	0.14	0.66	0.95	0.00	0.05	0.04	163.19	0.01	163.45	0.32
Concrete Pump	0.12	0.56	0.82	0.00	0.05	0.05	99.21	0.01	99.45	0.20
Concrete Saw	0.17	0.80	0.98	0.00	0.07	0.07	116.93	0.02	117.24	0.23
Generator	0.51	2.33	3.77	0.01	0.21	0.20	487.94	0.05	488.91	0.96
Aerial Lift (Man lift)	0.09	0.37	0.53	0.00	0.03	0.03	69.44	0.01	69.61	0.14
SUBTOTAL	3	13	17	0	1	1	2,096	0	2,101	4

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

Construction of 1 SCR for Refinery Boiler, Process Heater, or Gas Turbine

Construction			Round- trip Distance	Mileage Rate	2015 Mobile Source Emission Factors							
On-Road Equipment Type	Fuel	Number Needed	(miles/day)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Construction Worker Vehicle)	gasoline	20	50	20	0.00066	0.00614	0.00060	0.00001	0.00009	0.00006	1.10193	0.00006
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	100	8.9	0.00179	0.00767	0.02123	0.00004	0.00105	0.00088	4.20902	0.00008
Offsite (Delivery Truck - Medium Duty)	diesel	1	100	12.2	0.00174	0.01169	0.01285	0.00003	0.00050	0.00041	2.81248	0.00008
Onsite (Pickup Truck)	gasoline	5	4	20	0.00066	0.00614	0.00060	0.00001	0.00009	0.00006	1.10193	0.00006
Onsite (Watering Truck)	diesel	3	4	8.9	0.00174	0.01169	0.01285	0.00003	0.00050	0.00041	2.81248	0.00008

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	0.66	6.14	0.60	0.01	0.09	0.06	1101.93	0.06	1103.17	2.17
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.18	0.77	2.12	0.00	0.10	0.09	420.90	0.01	421.08	0.83
Offsite (Delivery Truck - Medium Duty)	0.17	1.17	1.29	0.00	0.05	0.04	281.25	0.01	281.42	0.55
Onsite (Pickup Truck)	0.01	0.12	0.01	0.00	0.00	0.00	22.04	0.00	22.06	0.04
Onsite (Watering Truck)	0.02	0.14	0.15	0.00	0.01	0.00	33.75	0.00	33.77	0.07
SUBTOTAL	**1**	**8**	**4**	**0**	**0**	**0**	**1,826**	**0**	**1,828**	**4**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)
*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Combustion Emissions from Construction Equipment	2.89	12.67	17.05	0.02	1.21	1.12	2095.60	0.26	2101.07	4.13
Combustion Emissions from On-Road Construction Vehicles	1.03	8.20	4.02	0.02	0.25	0.19	1826.12	0.08	1827.73	3.59
TOTAL for 1 SCR	**4**	**21**	**21**	**0**	**1**	**1**	**3,922**	**0**	**3,929**	**8**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

TOTAL for 2 SCRs Overlapping Construction	**8**	**42**	**42**	**0**	**3**	**3**	**7,843**	**1**	**7,858**	**15**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

TOTAL for 8 Facilities Overlapping Construction by Installing 2 SCRs each	**63**	**334**	**337**	**1**	**23**	**21**	**62,747**	**5**	**62,861**	**124**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

Construction of 1 SCR for Refinery Boiler, Process Heater, or Gas Turbine

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	1,040	Rough Terrain Crane (28 t	5.51	44.08	5,730.40	N/A	N/A
Operation of Portable Equipment	2,080	Welding Machines	10.02	160.32	20,841.60	N/A	N/A
Operation of Portable Equipment	130	Air Compressor	5.06	5.06	657.80	N/A	N/A
Operation of Portable Equipment	520	Backhoe	13.52	54.08	7,030.40	N/A	N/A
Operation of Portable Equipment	520	Plate Compactor	2.17	8.68	1128.40	N/A	N/A
Operation of Portable Equipment	390	Forklift	10.02	30.06	3907.80	N/A	N/A
Operation of Portable Equipment	260	Concrete Pump	3.25	6.50	845.00	N/A	N/A
Operation of Portable Equipment	260	Concrete Saw	1.75	3.50	455.00	N/A	N/A
Operation of Portable Equipment	1,040	Generator	5.06	40.48	5,262.40	N/A	N/A
Operation of Portable Equipment	260	Aerial Lift (Man lift)	1.75	3.50	455.00	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	50.00	6,500.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	11.24	1,460.67	11.24	1,460.67
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.20	1,065.57	8.20	1,065.57
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	1.00	130.00
Workers' Vehicles - Onsite	N/A	Watering Truck	N/A	N/A	N/A	1.35	175.28
TOTAL for 1 SCR				**376**	**48,840**	**72**	**9,332**
TOTAL for 2 SCRs Overlapping Construction				**751**	**97,680**	**144**	**18,663**
TOTAL for 8 Facilities Overlapping Construction by Installing @ SCRs each				**6,011**	**781,441**	**1,148**	**149,304**

Sources:

1. Off-Road Mobile Emission Factors, Scenario Year 2015
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/off-road-mobile-source-emission-factors
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/docs/default-source/ceqa/handbook/localized-significance-thresholds/particulate-matter-(pm)-2.5-significance-thresholds-and-calculation-methodology/final_pm2_5methodology.pdf?sfvrsn=2
3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2015
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Construction of 1 SCR for 1 FCCU

Install 1 SCR for 1 FCCU

Activity	Days/ wk	Hrs/day	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	8	4.33	21.67	12	260.00	140
				Total	12	**260.00**	

Construction	Max Equipment Rating		Operating Schedule	Usage Factor	2016 Mobile Source Emission Factors							
Off-Road Equipment Type	hp	Number Needed	(hr/day)		VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2 (lb/hr)	CH4 (lb/hr)
Crane	Composite	1	8	1	0.1073	0.4152	0.8625	0.0014	0.0352	0.0324	129	0.0097
Rough Terrain Crane (28 ton)	120	1	8	1	0.0690	0.3509	0.4155	0.0006	0.0341	0.0314	50.1	0.0062
Welding Machines	Composite	5	8	1	0.0434	0.1912	0.2054	0.0003	0.0150	0.0138	25.6	0.0039
Air Compressor	Composite	1	8	1	0.0641	0.3165	0.4318	0.0007	0.0282	0.0259	63.6	0.0058
Backhoe	Composite	1	8	1	0.0559	0.3666	0.3681	0.0008	0.0222	0.0204	66.8	0.0050
Plate Compactor	Composite	1	2	1	0.0050	0.0263	0.0314	0.0001	0.0012	0.0011	4.3	0.0005
Forklift	Composite	1	6	1	0.0399	0.2181	0.2493	0.0006	0.0119	0.0109	54.4	0.0036
Concrete Pump	Composite	1	2	1	0.0087	0.0417	0.0539	0.0001	0.0022	0.0021	7.2	0.0008
Concrete Saw	Composite	1	2	1	0.0679	0.3892	0.4267	0.0007	0.0298	0.0274	58.5	0.0061
Generator	Composite	2	8	1	0.0527	0.2821	0.4052	0.0007	0.0216	0.0198	61.0	0.0048
Aerial Lift (Man lift)	Composite	2	2	1	0.0358	0.1768	0.2310	0.0004	0.0134	0.0123	34.7	0.0032

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Crane (140 ton)	0.86	3.32	6.90	0.01	0.28	0.26	1029.02	0.08	1030.65	4.05
Rough Terrain Crane (28 ton)	0.55	2.81	3.32	0.00	0.27	0.25	401.18	0.05	402.23	1.58
Welding Machines	1.73	7.65	8.22	0.01	0.60	0.55	1024.11	0.16	1027.39	4.04
Air Compressor	0.51	2.53	3.45	0.01	0.23	0.21	508.86	0.05	509.83	2.00
Backhoe	0.45	2.93	2.94	0.01	0.18	0.16	534.38	0.04	535.22	2.10
Plate Compactor	0.01	0.05	0.06	0.00	0.00	0.00	8.63	0.00	8.65	0.03
Forklift	0.24	1.31	1.50	0.00	0.07	0.07	326.37	0.02	326.83	1.28
Concrete Pump	0.02	0.08	0.11	0.00	0.00	0.00	14.50	0.00	14.53	0.06
Concrete Saw	0.14	0.78	0.85	0.00	0.06	0.05	116.93	0.01	117.18	0.46
Generator	0.84	4.51	6.48	0.01	0.34	0.32	975.88	0.08	977.48	3.84
Aerial Lift (Man lift)	0.14	0.71	0.92	0.00	0.05	0.05	138.89	0.01	139.16	0.55
SUBTOTAL	**5**	**27**	**35**	**0**	**2**	**2**	**5,079**	**0**	**5,089**	**20**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
1 metric ton (MT) = 2,205 pounds
Construction GHGs are amortized over 30 years

Construction of 1 SCR for 1 FCCU

Construction					2016 Mobile Source Emission Factors							
On-Road Equipment Type	Fuel	Number Needed	Round- trip Distance (miles/day)	Mileage Rate (miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Construction Worker Vehicle)	gasoline	140	50	20	0.0006	0.0054	0.0005	0.0000	0.0001	0.0001	1.1063	0.0001
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	100	8.9	0.0015	0.0065	0.0169	0.0000	0.0008	0.0007	4.2082	0.0001
Offsite (Delivery Truck - Medium Duty)	diesel	1	100	12.2	0.0015	0.0100	0.0107	0.0000	0.0004	0.0003	2.8401	0.0001
Onsite (Pickup Truck)	gasoline	5	4	20	0.0006	0.0054	0.0005	0.0000	0.0001	0.0001	1.1063	0.0001
Onsite (Watering Truck)	diesel	3	4	12.2	0.0015	0.0100	0.0107	0.0000	0.0004	0.0003	2.8401	0.0001

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	4.21	37.65	3.59	0.08	0.66	0.43	7743.92	0.37	7751.72	30.47
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.15	0.65	1.69	0.00	0.08	0.07	420.82	0.01	420.96	1.65
Offsite (Delivery Truck - Medium Duty)	0.15	1.00	1.07	0.00	0.04	0.03	284.01	0.01	284.14	1.12
Onsite (Pickup Truck)	0.01	0.11	0.01	0.00	0.00	0.00	22.13	0.00	22.15	0.09
Onsite (Watering Truck)	0.02	0.12	0.13	0.00	0.01	0.00	34.08	0.00	34.10	0.13
SUBTOTAL	**5**	**40**	**6**	**0**	**1**	**1**	**8,505**	**0**	**8,513**	**33**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Construction GHGs are amortized over 30 years

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Combustion Emissions from Construction Equipment	5.49	26.69	34.77	0.06	2.10	1.93	5078.75	0.50	5089.16	20.00
Combustion Emissions from On-Road Construction Vehicles	4.53	39.53	6.49	0.08	0.80	0.54	8504.96	0.39	8513.07	33.46
TOTAL for 1 SCR	**10**	**66**	**41**	**0**	**3**	**2**	**13,584**	**1**	**13,602**	**53**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Construction of 1 SCR for 1 FCCU

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	2,080	Crane	1.75	14.00	3,640.00	N/A	N/A
Operation of Portable Equipment	2,080	Rough Terrain Crane (28 ton)	5.51	44.08	11,460.80	N/A	N/A
Operation of Portable Equipment	10,400	Welding Machines	10.02	400.80	104,208.00	N/A	N/A
Operation of Portable Equipment	2,080	Air Compressor	5.06	40.48	10,524.80	N/A	N/A
Operation of Portable Equipment	2,080	Backhoe	13.52	108.16	28,121.60	N/A	N/A
Operation of Portable Equipment	520	Plate Compactor	2.17	4.34	1128.40	N/A	N/A
Operation of Portable Equipment	1,560	Forklift	10.02	60.12	15631.20	N/A	N/A
Operation of Portable Equipment	520	Concrete Pump	3.25	6.50	1690.00	N/A	N/A
Operation of Portable Equipment	520	Concrete Saw	1.75	3.50	910.00	N/A	N/A
Operation of Portable Equipment	4,160	Generator	5.06	80.96	21,049.60	N/A	N/A
Operation of Portable Equipment	1,040	Aerial Lift (Man lift)	1.75	7.00	1820.00	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	350.00	91,000.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	11.24	2,921.35	11.24	2,921.35
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.20	2,131.15	8.20	2,131.15
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	1.00	260.00
Workers' Vehicles - Onsite	N/A	Watering Truck	N/A	N/A	N/A	0.98	255.74
TOTAL for 1 SCR				**789**	**205,237**	**371**	**96,568**
TOTAL for 2 SCR Overlapping Construction				**1,579**	**410,474**	**743**	**193,136**
TOTAL for 5 SCR Overlapping Construction in 2017				**3,947**	**1,026,184**	**1,857**	**482,841**

Sources:
1. Off-Road Mobile Emission Factors, Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/off-road-mobile-source-emission-factors
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/docs/default-source/ceqa/handbook/localized-significance-thresholds/particulate-matter-(pm)-2.5-significance-thresholds-and-calculation-methodology/final_pm2_5methodology.pdf?sfvrsn=2
3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Construction of 1 Berm for 1 Aqueous Ammonia Storage Tank

Fugitive PM10 Emissions Associated with Installing One Ammonia Tank for One SCR Retrofit (due to building containment berm)

1. GRADING ACTIVITIES (Backhoe)		
G = Fugitive PM10 Emission Rate (lbs/day) = 0.75 x T x 1.0 x $(S)^{1.5}$ x $(M)^{-1.4}$		*Source: AP-42, 10/98, Table 11.9-1 (PM10 Equation for Overburden Bulldozing)*
S = Silt Content	7.5 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
M = Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
T = max hours of operation/day	8 hr/day	
G = Fugitive PM10 =	**46.70 lbs/day**	

2. TRENCHING/STOCKPILE LOADING (Backhoe)		
LPM10 = Emission Factor per particle size (lbs/ton) = kPM10 x (0.0032) x $(U/5)^{1.3}$ x $(M/2)^{-1.4}$		*Source: AP-42, 01/95, p. 13.2.4-3 (Equation 1 for English Units)*
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (See Mine I)*
M = Material Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Overburden Bulldozing)*
kPM10 = Particle Size Multiplier for PM10	0.35 dimensionless	*Source: AP-42, 01/95, p. 13.2.4-3*
G = Maximum Daily Weight of Material Moved	10 tons/day	Note: One backhoe can trench approximately 0.1 acre per day or 4,356 square feet per day, with a cut of 3 feet in depth, 13,068 cubic feet = 484 cubic yards and 1 cubic yard = 1 ton soil.
Tday, t = Truck Operating time, maximum	8 hr/day	
LPM10 = Emission Factor per particle size =	0.0035 lbs PM10/ton soil moved	
PPM10 = Emission Rate based on particle size = (LPMx G) =	**0.03 lbs PM10/day**	

3. STOCKPILE WIND EROSION		
Q = Wind Erosion Emission Rate based on particle size (lbs/day) = kPM10* 0.72 x U x Tc * (A x B /43,560 sq. ft/acre)		*Source: AP-42, 10/98, Table 11.9-1 (Emission Factor Equation for Active Storage Pile)*
A = Length of Stockpile	15 ft	
B = Width of Stockpile	15 ft	
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (General Characteristics of Surface Coal Mines - Mine I)*
kPM10 = Particle Size Multiplier for PM10	0.5 dimensionless	*Source: AP-42, 01/95, p. 13.2.5-3 (PM10 Aerodynamic Particle Size Multiplier (k) for Equation 2)*
Tc = Time Piles Remain Uncovered	24 hr/day	Note: This calculation assumes that the piles remain uncovered for 24 hours/day.
QPM10 =	**0.54 lbs PM10/day**	

4. TRUCK FILLING/DUMPING	
TF = Fugitive PM10 Emissions From Truck Filling = G (ton/day) x TF, PM10 (lb/ton)	
TD = Fugitive PM10 Emissions From Truck Dumping = G (ton/day) x TD, PM10 (lb/ton)	
TFPM10 = Emission Factor for Truck Filling =	0.0221 lb/ton of material moved
TDPM10 = Emission Factor for Truck Dumping =	0.0091 lb/ton of material moved
G = Maximum Daily Weight of Material Trucked Away	1 ton/day
TF =	**0.02 lbs PM10/day**
TD =	**0.01 lbs PM10/day**

FUGITIVE PM10 EMISSIONS SUMMARY

Activity	**Unmitigated PM10 (lbs/day)**	**Mitigated PM10 [1] (lbs/day)**
1. Grading	46.70	18.21
2. Trenching/Stockpile Loading	0.03	0.01
3. Storage Piles - Wind Erosion	0.54	0.21
4. Truck Filling/Dumping	0.03	0.01
TOTAL FOR 1 NH3 TANK BERM + 1 SCR	**47.30**	**18.45**
TOTAL FOR 2 NH3 TANK BERMS + 2 SCRS	**94.60**	**36.89**
TOTAL FOR 5 NH3 TANK BERMS + 5 SCRS	**236.50**	**92.23**

[1] Water three times per day per SCAQMD Rule 403 (61% control efficiency)

Construction of 1 Berm for 1 Aqueous Ammonia Storage Tank

Fugitive PM10 Emissions Associated with Installing One Ammonia Tank for One SCR Retrofit (due to building containment berm)

1. GRADING ACTIVITIES (Backhoe)		
G = Fugitive PM10 Emission Rate (lbs/day) = 0.75 x T x 1.0 x $(S)^{1.5}$ x $(M)^{-1.4}$		*Source: AP-42, 10/98, Table 11.9-1 (PM10 Equation for Overburden Bulldozing)*
S = Silt Content	7.5 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
M = Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
T = max hours of operation/day	8 hr/day	
G = Fugitive PM10 =	**46.70 lbs/day**	

2. TRENCHING/STOCKPILE LOADING (Backhoe)		
LPM10 = Emission Factor per particle size (lbs/ton) = kPM10 x (0.0032) x $(U/5)^{1.3}$ x $(M/2)^{-1.4}$		*Source: AP-42, 01/95, p. 13.2.4-3 (Equation 1 for English Units)*
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (See Mine I)*
M = Material Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Overburden Bulldozing)*
kPM10 = Particle Size Multiplier for PM10	0.35 dimensionless	*Source: AP-42, 01/95, p. 13.2.4-3*
G = Maximum Daily Weight of Material Moved	10 tons/day	Note: One backhoe can trench approximately 0.1 acre per day or 4,356 square feet per day, with a cut of 3 feet in depth, 13,068 cubic feet = 484 cubic yards and 1 cubic yard = 1 ton soil.
Tday, t = Truck Operating time, maximum	8 hr/day	
LPM10 = Emission Factor per particle size =	0.0035 lbs PM10/ton soil moved	
PPM10 = Emission Rate based on particle size = (LPMx G) =	**0.03 lbs PM10/day**	

3. STOCKPILE WIND EROSION		
Q = Wind Erosion Emission Rate based on particle size (lbs/day) = kPM10* 0.72 x U x Tc * (A x B /43,560 sq. ft/acre)		*Source: AP-42, 10/98, Table 11.9-1 (Emission Factor Equation for Active Storage Pile)*
A = Length of Stockpile	15 ft	
B = Width of Stockpile	15 ft	
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (General Characteristics of Surface Coal Mines - Mine I)*
kPM10 = Particle Size Multiplier for PM10	0.5 dimensionless	*Source: AP-42, 01/95, p. 13.2.5-3 (PM10 Aerodynamic Particle Size Multiplier (k) for Equation 2)*
Tc = Time Piles Remain Uncovered	24 hr/day	Note: This calculation assumes that the piles remain uncovered for 24 hours/day.
QPM10 =	**0.54 lbs PM10/day**	

4. TRUCK FILLING/DUMPING	
TF = Fugitive PM10 Emissions From Truck Filling = G (ton/day) x TF, PM10 (lb/ton)	
TD = Fugitive PM10 Emissions From Truck Dumping = G (ton/day) x TD, PM10 (lb/ton)	
TFPM10 = Emission Factor for Truck Filling =	0.0221 lb/ton of material moved
TDPM10 = Emission Factor for Truck Dumping =	0.0091 lb/ton of material moved
G = Maximum Daily Weight of Material Trucked Away	1 ton/day
TF =	**0.02 lbs PM10/day**
TD =	**0.01 lbs PM10/day**

FUGITIVE PM10 EMISSIONS SUMMARY		
Activity	**Unmitigated PM10 (lbs/day)**	**Mitigated PM10 [1] (lbs/day)**
1. Grading	46.70	18.21
2. Trenching/Stockpile Loading	0.03	0.01
3. Storage Piles - Wind Erosion	0.54	0.21
4. Truck Filling/Dumping	0.03	0.01
TOTAL FOR 1 NH3 TANK BERM + 1 SCR	**47.30**	**18.45**
TOTAL FOR 2 NH3 TANK BERMS + 2 SCRS	**94.60**	**36.89**
TOTAL FOR 5 NH3 TANK BERMS + 5 SCRS	**236.50**	**92.23**

[1] Water three times per day per SCAQMD Rule 403 (61% control efficiency)

Diesel Idling Health Risk Assessment

Peak Operational Truck Trips per year at one facility (Refinery 6) = 147

EF, g/hr	Annual No of Trips	Idling, h/y	Emisions, lb/yr	Emisions, ton/yr
1.67	147	36.75	0.14	6.78E-05

Heavy-duty idling rates from emfac2011_idling_emission_rates.xlsx (http://www.arb.ca.gov/msei/emfac2011_idling_emission_rates.xlsx).

Emisions, ton/yr	Cancer Potency Factor, (mg/kg-d)-1	X/Q at 25 m, (ug/m3)/(ton/yr)	CEF	MP	MWHF	Carcinogenic Health Risk	Screening Level	Significant?
6.78E-05	1.1	29.64	676.63	1	1	1.50E-06	1.00E-05	NO

Carcinogenic health risk = emissions, ton/yr x cancer potency, (mg/kg-day)-1 x X/Q, (ug/m3)/(ton/yr) x CEF x MP x MWHF

Offsite Consequence Analysis for Aqueous Ammonia Spill at a Refinery

Offsite Consequence Input Data for NH3 spill of one 11,000 gallon storage tank at a refinery facility

Ammonia Storage, gal	Berm Capacity, gal	Ammonia Berm, ft3	Height of Berm, ft	Area, ft2
11,000	12,100	1,618	3.0	539

Berms must be able to contain 110% the volume of the tank
Typical berm heights are three feet tall.

Ammonia Slip Calculation

Ammonia Slip Conc at the Exit of the Stack, ppm	Dispersion Factor	Molecular Weight, g/mol	Peak Conc at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index	Chronic Hazard Index
5	0.01	17.03	35	3,200	200	0.01	0.17

Ammonia slip is limited to five ppm by permitting.
Conc., ug/m3 = (conc., ppm x 1,000 x molecular weight, g/mol)/24.5 m3/kmol

Based on the Staff Report for Toxic Air Contaminants 1401.1 – Requirements for New and Relocated Facilities Near Schools, and 1402 – Control of Toxic Air Contaminants from Existing Source, June 2015 the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack.

Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

RMP*Comp

RMP*Comp

Back

Estimated Distance Calculation

Estimated distance to toxic endpoint: 0.1 miles (0.2 kilometers)

This is the downwind distance to the toxic endpoint specified for this regulated substance under the RMP Rule. Report all distances shorter than 0.1 mile as 0.1 mile, and all distances longer than 25 miles as 25 miles.

Scenario Summary

Chemical:	Ammonia (water solution)
Initial concentration:	20 %
CAS number:	7664-41-7
Threat type:	Toxic Liquid
Scenario type:	Worst-case
Liquid temperature:	25 C
Quantity released:	12100 gallons
Mitigation measures:	
Diked area:	539 square feet
Dike height:	3 feet
Release rate to outside air:	11.7 pounds per minute
Surrounding terrain type:	Urban surroundings (many obstacles in the immediate area)
Toxic endpoint:	0.14 mg/L; basis: ERPG-2

Assumptions about this scenario

Wind speed:	1.5 meters/second (3.4 miles/hour)
Stability class:	F
Air temperature:	77 degrees F (25 degrees C)

Construction of 1 Scrubber (Wet or Dry)

Activity	No. of Scrubbers	
Phase I: Demolition	1	Preparation to Install WGS or DGS

Activity	Days/ wk	Wks/ month	Days/ month	Months	Total Days	Crew Size
Demolition	5	4.33	21.67	1	21.67	50
Construction	5	4.33	21.67	17	368.33	175
			Total	**18**	**390**	

Phase I: Demolition		Rating	Number	Operation Schedule	2016 Off-Road Emission Factors							
Off-Road Equipment Type	**Fuel**	**(hp)**	**Needed**	**(hr/day)**	**VOC (lb/hr)**	**CO (lb/hr)**	**NOx (lb/hr)**	**SOx (lb/hr)**	**PM10 (lb/hr)**	**PM2.5 (lb/hr)**	**CO2 (lb/hr)**	**CH4 (lb/hr)**
crane	diesel	comp	1	8	0.097200	0.331700	0.278900	0.000240	0.027900	0.025600	25.348000	0.007650
front end loader	diesel	comp.	1	8	0.042600	0.301600	0.406900	0.000390	0.031300	0.028800	40.459700	0.012200
forklift	diesel	comp.	1	8	0.057200	0.318300	0.492300	0.000380	0.041200	0.037900	40.003700	0.012100
concrete saw	diesel	comp.	1	8	0.080800	0.471900	0.577800	0.000780	0.043400	0.043400	74.083200	0.007170
jack hammer	diesel	comp.	1	8	0.061400	0.314000	0.395400	0.000500	0.032800	0.032800	46.908000	0.005530

Phase I: Demolition		Number	Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	**Fuel**	**Needed**	**(miles/day)**	**(miles/ gallon)**	**VOC (lb/mile)**	**CO (lb/mile)**	**NOx (lb/mile)**	**SOx (lb/mile)**	**PM10 (lb/mile)**	**PM2.5 (lb/mile)**	**CO2 (lb/mile)**	**CH4 (lb/mile)**
Offsite (Construction Worker Vehicle)	gasoline	50	30	20	0.002910	0.011000	0.000880	0.000010	0.000780	0.000220	1.030600	0.000070
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	3	50	4.89	0.007800	0.148000	0.033200	0.000060	0.001170	0.000500	5.440400	0.000080
Offsite (Delivery Truck - Medium Duty)	diesel	5	50	6	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060
Onsite (Pickup Truck)	gasoline	1	10	20	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060
Onsite (Watering Truck - Medium Duty)	diesel	1	10	6	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060

Incremental Increase in Onsite Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
crane	0.78	2.65	2.23	0.00	0.22	0.20	202.78	0.06
front end loader	0.34	2.41	3.26	0.00	0.25	0.23	323.68	0.10
forklift	0.46	2.55	3.94	0.00	0.33	0.30	320.03	0.10
concrete saw	0.65	3.78	4.62	0.01	0.35	0.35	592.67	0.06
jack hammer	0.49	2.51	3.16	0.00	0.26	0.26	375.26	0.04
SUBTOTAL	**2.71**	**13.90**	**17.21**	**0.02**	**1.41**	**1.35**	**1814.42**	**0.36**

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lbs/day)

Construction of 1 Scrubber (Wet or Dry)

Incremental Increase in Offsite Combustion Emissions from Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
Offsite (Construction Worker Vehicle)	4.37	16.50	1.32	0.02	1.17	0.33	1545.90	0.11
Offsite (Flatbed Truck - Heavy-Heavy Duty)	1.17	22.20	4.98	0.01	0.18	0.08	816.06	0.01
Offsite (Delivery Truck - Heavy Duty)	1.64	25.10	7.38	0.01	0.30	0.13	1172.00	0.02
Onsite (Pickup Truck)	0.07	1.00	0.30	0.00	0.01	0.01	46.88	0.00
Onsite (Watering Truck - Medium Duty)	0.07	1.00	0.30	0.00	0.01	0.01	46.88	0.00
SUBTOTAL	**7.31**	**65.81**	**14.27**	**0.04**	**1.67**	**0.55**	**3627.72**	**0.13**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Total Incremental Combustion Emissions from Construction Activities	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT*)
Phase I: Demolition TOTAL	**10**	**80**	**31**	**0.06**	**3**	**2**	**5442**	**0**	**5452**	**2**
Significant Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; GHGs from temporary construction activities are amortized over 30 years.

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Demolition Hours	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/phase I)	Total Gasoline Fuel Usage (gal/phase I)
Operation of Portable Equipment	173	crane	3.9	31.20	N/A	676.00	N/A
Operation of Portable Equipment	173	front end loader	2.1	16.80	N/A	364.00	N/A
Operation of Portable Equipment	173	Forklift	1.1	8.80	N/A	190.67	N/A
Operation of Portable Equipment	173	Concrete Saw	1.5	12.00	N/A	260.00	N/A
Operation of Portable Equipment	173	jack hammer	1.5	12.00	N/A	260.00	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	75.00	N/A	1625.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	30.67	N/A	664.62	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	41.67	N/A	902.78	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	0.50	N/A	10.83
Workers' Vehicles - Onsite Hauling	N/A	Watering Truck	N/A	1.67	N/A	36.11	N/A
			TOTAL	**155**	**76**	**3,354**	**1,636**

Sources:
1. Off-Road Mobile Emission Factors, Scenario Year 2016
   EF from Burden in EMFAC2011
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Construction of 1 Scrubber (Wet or Dry)

Phase II: Fugitive PM10 Emissions (e.g., Fugitive Dust) Associated with foundation work for WGS or DGS Installation

1. GRADING ACTIVITIES (Backhoe)		
G = Fugitive PM10 Emission Rate (lbs/day) = 0.75 x T x 1.0 x $(S)^{1.5}$ x $(M)^{-1.4}$		*Source: AP-42, 10/98, Table 11.9-1 (PM10 Equation for Overburden Bulldozing)*
S = Silt Content	7.5 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
M = Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
T = max hours of operation/day	8 hr/day	
G = Fugitive PM10 =	**46.70 lbs/day**	

2. TRENCHING/STOCKPILE LOADING (Backhoe)		
LPM10 = Emission Factor per particle size (lbs/ton) = kPM10 x (0.0032) x $(U/5)^{1.3}$ x $(M/2)^{-1.4}$		*Source: AP-42, 01/95, p. 13.2.4-3 (Equation 1 for English Units)*
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (See Mine I)*
M = Material Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Overburden Bulldozing)*
kPM10 = Particle Size Multiplier for PM10	0.35 dimensionless	*Source: AP-42, 01/95, p. 13.2.4-3*
G = Maximum Daily Weight of Material Moved	1 tons/day	Note: One backhoe can trench approximately 0.1 acre per day or 4,356 square feet per day, with a cut of 3 feet in depth, 13,068 cubic feet = 484 cubic yards and 1 cubic yard = 1 ton soil.
Tday, t = Truck Operating time, maximum	5 hr/day	
LPM10 = Emission Factor per particle size =	0.0035 lbs PM10/ton soil moved	
PPM10 = Emission Rate based on particle size = (LPMx G) =	**0.0035 lbs PM10/day**	

3. STOCKPILE WIND EROSION		
Q = Wind Erosion Emission Rate based on particle size (lbs/day) = kPM10* 0.72 x U x Tc * (A x B /43,560 sq. ft/acre)		*Source: AP-42, 10/98, Table 11.9-1 (Emission Factor Equation for Active Storage Pile)*
A = Length of Stockpile	21 ft	
B = Width of Stockpile	21 ft	
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (General Characteristics of Surface Coal Mines - Mine I)*
kPM10 = Particle Size Multiplier for PM10	0.5 dimensionless	*Source: AP-42, 01/95, p. 13.2.5-3 (PM10 Aerodynamic Particle Size Multiplier (k) for Equation 2)*
Tc = Time Piles Remain Uncovered	24 hr/day	Note: This calculation assumes that the piles remain uncovered for 24 hours/day.
QPM10 =	**1.05 lbs PM10/day**	

4. TRUCK FILLING/DUMPING	
TF = Fugitive PM10 Emissions From Truck Filling = G (ton/day) x TF, PM10 (lb/ton)	
TD = Fugitive PM10 Emissions From Truck Dumping = G (ton/day) x TD, PM10 (lb/ton)	
TFPM10 = Emission Factor for Truck Filling =	0.0221 lb/ton of material moved
TDPM10 = Emission Factor for Truck Dumping =	0.0091 lb/ton of material moved
G = Maximum Daily Weight of Material Trucked Away	1 ton/day
TF =	**0.02 lbs PM10/day**
TD =	**0.01 lbs PM10/day**

FUGITIVE PM10 EMISSIONS SUMMARY

Activity	**Unmitigated PM10 (lbs/day)**	**Mitigated PM10 [1] (lbs/day)**
1. Grading	46.70	18.21
2. Trenching/Stockpile Loading	0.00	0.00
3. Storage Piles - Wind Erosion	1.05	0.41
4. Truck Filling/Dumping	0.03	0.01
TOTAL	**47.78**	**18.64**

[1] Water three times per day per SCAQMD Rule 403 (61% control efficiency)

Construction of 1 Scrubber (Wet or Dry)

Activity	No. of Scrubbers	
Phase II: Construction	1	Install WGS or DGS

Activity	Days/wk	Wks/month	Days/month	Months	Total Days	Crew Size
Demolition	5	4.33	21.67	1	21.67	50
Construction	5	4.33	21.67	17	368.33	175
			Total	18	390	

Phase II: Construction		Rating	Number	Operation Schedule	2016 Off-Road Emission Factors							
Off-Road Equipment Type	Fuel	(hp)	Needed	(hr/day)	VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2 (lb/hr)	CH4 (lb/hr)
backhoe	diesel	comp.	1	8	0.0426	0.3016	0.4069	0.0004	0.0313	0.0288	40.5	0.0122
crane	diesel	comp.	2	8	0.0972	0.3317	0.2789	0.0002	0.0279	0.0256	25	0.0077
aerial lift	diesel	comp.	3	8	0.0216	0.4173	0.3549	0.0006	0.0146	0.0134	66.0	0.0199
forklift	diesel	comp.	1	8	0.0572	0.3183	0.4923	0.0004	0.0412	0.0379	40.0	0.0121
generator	diesel	comp.	1	8	0.0799	0.4754	0.6043	0.0008	0.0424	0.0424	77.9	0.0071
welder	diesel	comp.	10	8	0.0553	0.2932	0.3713	0.0005	0.0297	0.0297	45.0	0.0050
cement mixer	diesel	comp.	1	2	0.0074	0.0386	0.0462	0.0001	0.0019	0.0019	6.3	0.0007

Phase II: Construction		Number	Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	Fuel	Needed	(miles/day)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Construction Worker Vehicle)	gasoline	175	30	20	0.002910	0.011000	0.000880	0.000010	0.000780	0.000220	1.030600	0.000070
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	3	50	4.89	0.007800	0.148000	0.033200	0.000060	0.001170	0.000500	5.440400	0.000080
Offsite (Delivery Truck - Medium Duty)	diesel	5	50	6	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060
Onsite (Pickup Truck)	gasoline	1	10	20	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060

Incremental Increase in Onsite Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
backhoe	0.34	2.41	3.26	0.00	0.25	0.23	323.68	0.10
crane	1.56	5.31	4.46	0.00	0.45	0.41	405.57	0.12
aerial lift	0.52	10.02	8.52	0.02	0.35	0.32	1583.75	0.48
forklift	0.46	2.55	3.94	0.00	0.33	0.30	320.03	0.10
generator	0.64	3.80	4.83	0.01	0.34	0.34	623.03	0.06
welder	4.42	23.46	29.70	0.04	2.38	2.38	3597.29	0.40
cement mixer	0.01	0.08	0.09	0.00	0.00	0.00	12.63	0.00
SUBTOTAL	**7.95**	**47.62**	**54.80**	**0.07**	**4.10**	**3.98**	**6865.97**	**1.25**

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lbs/day)

Incremental Increase in Offsite Combustion Emissions from Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
Offsite (Construction Worker Vehicle)	15.28	57.75	4.62	0.05	4.10	1.16	5410.65	0.37
Offsite (Flatbed Truck - Heavy-Heavy Duty)	1.17	22.20	4.98	0.01	0.18	0.08	816.06	0.01
Offsite (Delivery Truck - Medium Duty)	1.64	25.10	7.38	0.01	0.30	0.13	1172.00	0.02
Onsite (Pickup Truck)	0.07	1.00	0.30	0.00	0.01	0.01	46.88	0.00
SUBTOTAL	**18.16**	**106.05**	**17.27**	**0.07**	**4.58**	**1.37**	**7445.59**	**0.40**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Construction of 1 Scrubber (Wet or Dry)

FUGITIVE PM10 EMISSIONS SUMMARY				
Activity	Unmitigated PM10 (lbs/day)	Mitigated PM10 [1] (lbs/day)	Unmitigated PM2.5 (lbs/day)	Mitigated PM2.5 [1] (lbs/day)
1. Grading	46.70	18.21	9.71	4.86
2. Trenching/Stockpile Loading	0.00	0.00	0.00	0.00
3. Storage Piles - Wind Erosion	1.05	0.41	0.22	0.11
4. Truck Filling/Dumping	0.03	0.01	0.01	0.00
SUBTOTAL	**47.78**	**18.64**	**9.94**	**4.97**

[1] Water two times per day per SCAQMD Rule 403 (50% control efficiency)

Total Incremental Combustion Emissions from Construction Activities	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT)*
Phase II: Construction TOTAL	**26**	**154**	**72**	**0.14**	**27**	**10**	**14312**	**2**	**14346**	**80**
Significant Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	n/a

*1 metric ton (MT) = 2,205 pounds; GHGs from temporary construction activities are amortized over 30 years.

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/phase II)	Total Gasoline Fuel Usage (gal/phase II)
Operation of Portable Equipment	2947	backhoe	2.1	16.80	N/A	6,188.00	N/A
Operation of Portable Equipment	2947	crane	3.9	62.40	N/A	11,492.00	N/A
Operation of Portable Equipment	2947	aerial lift	1.2	28.80	N/A	3,536.00	N/A
Operation of Portable Equipment	2947	forklift	1.1	8.80	N/A	3,241.33	N/A
Operation of Portable Equipment	2947	generator	4.2	33.60	N/A	12,376.00	N/A
Operation of Portable Equipment	2947	welder	1.18	94.40	N/A	3,477.07	N/A
Operation of Portable Equipment	737	cement mixer	2.8	5.60	N/A	2,062.67	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	262.50	N/A	96,687.50
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	30.67	N/A	11,298.57	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	41.67	N/A	15,347.22	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	0.50	N/A	184.17
			TOTAL	**323**	**263**	**69,019**	**96,872**

Sources:
1. Off-Road Mobile Emission Factors, Scenario Year 2016
http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html/offroadEF07_25.xls
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc
3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2016
http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEF07_26.xls
http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEFHHDT07_26.xls

Construction of 1 Scrubber (Wet or Dry)

Overlapping Phase I and Phase II

One Facility Undergoing Demolition Overlapping with One Facility Under Construction										
Total Incremental Combustion Emissions from Construction Activities	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT*)
Phase I: Demolition TOTAL	**10**	**80**	**31**	**0**	**3**	**2**	**5,442**	**0**	**5,452**	**2**
Phase II: Construction TOTAL	**26**	**154**	**72**	**0**	**27**	**10**	**14,312**	**2**	**14,346**	**80**
Overlapping Phase I + Phase II TOTAL	**36**	**233**	**104**	**0**	**30**	**12**	**19,754**	**2**	**19,799**	**82**
Significant Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/both phases)	Total Gasoline Fuel Usage (gal/both phases)
Phase I: Demolition TOTAL	155	76	3,354	1,636
Phase II: Construction TOTAL	323	263	69,019	96,872
Overlapping Phase I + Phase II TOTAL	478	339	72,373	98,508

Construction of 1 Scrubber (Wet or Dry)

Construction Water Use

Refinery ID	plot space (sf) for WGS or DGS	Acreage
1	3,953	0.090748
2	371	0.008523
3	0	0
4	1,575	0.036157
5	11,860	0.272268
6	5,930	0.136134
7	0	0
8	3,953	0.090748
9	1,575	0.036157
Total	**29,217**	**1**

Area Disturbed, ft2	Depth of Water, ft*	Water Use, ft3	Water Use, gal	Number of Waterings per day	Total Daily Water Use, gal
29,217	0.005	146	1,093	3	3,278

*Assumes 1/16 inch depth of water applied per washing

USAGE DATA FOR NON-REFINERY FACILITIES

Non-Refinery Facility Number	Affected Device	Proposed NOx Control	NH3Tank Size, gallon	NH3 Use, ton/yr	NH3 Use, gal/yr	Urea Use, gal/yr	Electricity, kwh/yr	Hydrated Lime Tank Capacity, lb	Hydrated Lime, lb/yr	Catalyst Delivered, ton/yr	Catalyst Delivered, ft3/yr	Solid Waste, lb/yr	Filter Waste, lb/yr	NH3/Urea Number of Delivery Trips	Hydrated Lime Number of Delivery Trips	Solid Waste Number of Haul Trips	Filter Waste Minimum Number of Haul Trips	Catalyst Delivery	TOTAL per year
1	Turbines	3 SCRs	5,000	742.5	193,857		5,183,169	N/A	N/A			N/A	N/A	39					
1	ICEs	5 SCRs	1,000			16,134	61,269	N/A	N/A	0.9		N/A	N/A	17					
2	Turbines	4 SCRs	2,000	81.8	21,355		1,052,422	N/A	N/A			N/A	N/A	11					
2	ICEs	6 SCRs	1,000			19,659	74,656	N/A	N/A	3.28		N/A	N/A	20					
3	ICEs	5 SCRs	1,000			44,368	168,490	N/A	N/A	2.46		N/A	N/A	45					
4	Turbine	1 SCR	2,000	178.1	46,510		222,099	N/A	N/A			N/A	N/A	23					
5	Turbines	2 SCRs	2,000	52.2	13,622		444,198	N/A	N/A			N/A	N/A	7					
6	Turbine	1 SCR	2,000	195.1	50,933		222,099	N/A	N/A			N/A	N/A	25					
7	Turbines	2 SCRs	2,000	158.9	41,479		3,419,977	N/A	N/A			N/A	N/A	21					
8	Glass Furnace	2 SCRs	1,000	20.5	5,352		258,007	N/A	N/A			N/A	N/A	5					
8	Glass Furnace	1 DGS	1,062	0.9	113,126		806,270	150,000	682,229		1315	837,281	5,664	107	5	11	1	0	123
9	SiO2:Na2O Furnace	1 SCR	600	2.7	42,048		455,520	N/A	N/A		328	N/A	N/A	70					
10	Metal Heat Treating	SCR mfr 1	2,000	182.6	47,688		2,091,180	N/A	N/A		743			24					
10	Metal Heat Treating	SCR mfr 2	2,000	182.6	47,688		2,091,180	N/A	N/A		743			24					
11	Turbines	SCR (Replacement)	10,000	407	106,078		Same	N/A	N/A		Same	N/A	N/A	Existing					
				1,798	**623,657**	**80,161**	**16,550,537**	**150,000**	**682,229**	**7**	**3,130**	**837,281**	**5,664**	**437**	**5**	**11**	**1**	**0**	**454**

Facility 8 has two options, SCR or DGS.
Faciliy 11 has an existing NH3 tank and the annual usage is existing, not an increase.
The type of ammonia to be used is aqueous, 19% by weight.
Assumed that haul and delivery trucks can hold 20 yd3 of material.

Non-Refinery Facility Number	Electricity, kwh/yr	Electricity, kwh/day	Electricity, Mwh/day	Instantaneous Electricity, MW
1	5,183,169	14,200	14.20	0.59
1	61,269	168	0.17	0.01
2	1,052,422	2,883	2.88	0.12
2	74,656	205	0.20	0.01
3	168,490	462	0.46	0.02
4	222,099	608	0.61	0.03
5	444,198	1,217	1.22	0.05
6	222,099	608	0.61	0.03
7	3,419,977	9,370	9.37	0.39
8	258,007	707	0.71	0.03
8	806,270	2,209	2.21	0.09
9	455,520	1,248	1.25	0.05
10	2,091,180	5,729	5.73	0.24
10	2,091,180	5,729	5.73	0.24
11	0	0	0	0.00
	16,550,537	**45,344**	**45**	**1.89**

Note: Instantaneous Electricity Equation: 45,344 kW-hr/day x 1 work day/24 hr x 1 MW/1000 kW = 1.9 MW

UTILITY PROVIDERS AND SCHOOL/AIRPORT LOCATIONS FOR NON-REFINERY FACILITIES

Non-Refinery Facility Number	Equipment/Source Category	Nox Control Technology Assumed to Be Installed	County	Equipment	Electricity Provider	Natural Gas Provider	Solid Waste
1	Utility	5 SCR - ICE, 3 SCR - turbine	Los Angeles	ICE, turbine	Self	So Cal Gas	Sunshine Canyon Landfill
2	Utility	6 SCR - ICE, 4 SCR - turbine	Riverside	ICE, turbine	Self	So Cal Gas	Badlands Sanitary Landfill
3	Utility	5 SCR	Los Angeles	ICE	Self/SCE	So Cal Gas	Chiquita Canyon Landfill
4	State Hospital Utility	1 SCR	Los Angeles	Turbine	Self/SCE	So Cal Gas	
5	Airport	2 SCR	Los Angeles	Turbine	Self/DWP	So Cal Gas	Sunshine Canyon Landfill
6	Paper mfg	1 SCR	San Bernardino	Turbine	Self/SCE	So Cal Gas	Milliken Sanitary Landfill
7	Oil Field	2 SCR	Los Angeles	Turbine	Self/SCE	So Cal Gas	Chiquita Canyon Landfill
8	Container Glass Mfg	2 SCRs or 1 DGS	Los Angeles	Glass furnace	City of Vernon	City of Vernon	
9	Glass mfg	1 DGS or 1 SCR	Los Angeles	SiO_2:Na_2O furnace	SCE	So Cal Gas	South Gate Transfer Station
10	Metal forging	1 SCR	San Bernardino	Heat treating furnace	SCE	So Cal Gas	Mid-Valley Landfill

SUMMARY OF CONSTRUCTION SCHEDULE

Construction Schedule Assumptions applied in CalEEMod

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250
4	Paving	Paving	6/8/2016	6/14/2016	5	5

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Building Construction	Cranes	1	6	226	0.29
Building Construction	Forklifts	1	6	89	0.2
Building Construction	Generator Sets	1	8	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6	97	0.37
Building Construction	Welders	2	8	46	0.45
Building Construction	Aerial Lifts	1	8	62	0.31
Demolition	Concrete/Industrial Saws	1	8	81	0.73
Demolition	Rubber Tired Dozers	1	8	255	0.4
Demolition	Tractors/Loaders/Backhoes	1	8	97	0.37
Demolition	Cranes	1	8	226	0.29
Paving	Cement and Mortar Mixers	1	6	9	0.56
Paving	Paving Equipment	1	8	130	0.36
Paving	Plate Compactors	1	6	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation	Rubber Tired Dozers	1	7	255	0.4
Site Preparation	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation	Trenchers	1	8	80	0.5

SUMMARY OF CONSTRUCTION EMISSIONS OUTPUT FROM CALEEMOD

Summary of CalEEMOD Output Files For Non-Refinery Construction Analysis

Winter Unmitigated (lb/day)

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
2016	3.67280	31.70130	21.69720	0.03430	5.88900	1.71300	7.08700	2.97740	1.62670	4.07960	0.00000	3,285.52660	3,285.52660	0.69830	0.00000	3,300.19040
2017	2.62890	18.82150	15.23760	0.02490	0.24500	1.13660	1.38150	0.06580	1.09010	1.15600	0.00000	2,336.75790	2,336.75790	0.44460	0.00000	2,346.09480
Total	3.67280	31.70130	21.69720	0.03430	5.88900	1.71300	7.08700	2.97740	1.62670	4.07960	0.00000	3,285.52660	3,285.52660	0.69830	0.00000	3,300.19040

Winter Mitigated (lb/day)

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
2016	3.6728	31.7013	21.6972	0.0343	2.3513	1.7130	3.5493	1.1757	1.6267	2.2778	0.0000	3,285.5266	3,285.5266	0.6983	0.0000	3,300.1904
2017	2.6289	18.0249	15.2376	0.0249	0.2450	1.1366	1.3815	0.0658	1.0901	1.1560	0.0000	2,336.7579	2,336.7579	0.4446	0.0000	2,346.0948
Total	3.6728	31.7013	21.6972	0.0343	2.3513	1.7130	3.5493	1.1757	1.6267	2.2778	0.0000	3,285.5266	3,285.5266	0.6983	0.0000	3,300.1904

Summer Unmitigated (lb/day)

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
2016	3.6645	31.6449	21.7158	0.0346	5.8890	1.7129	7.0870	2.9774	1.6266	4.0796	0.0000	3,309.6669	3,309.6669	0.6983	0.0000	3,324.3300
2017	2.6227	18.7997	15.1854	0.0251	0.2450	1.1365	1.3815	0.0658	1.0901	1.1559	0.0000	2,350.8133	2,350.8133	0.4446	0.0000	2,360.1495
Total	3.6645	31.6449	21.7158	0.0346	5.8890	1.7129	7.0870	2.9774	1.6266	4.0796	0.0000	3,309.6669	3,309.6669	0.6983	0.0000	3,324.3300

Summer Mitigated (lb/day)

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
2016	3.6645	31.6449	21.7158	0.0346	2.3513	1.7129	3.5493	1.1757	1.6266	2.2778	0.0000	3,309.6669	3,309.6669	0.6983	0.0000	3,324.3300
2017	2.6227	18.0031	15.1854	0.0251	0.2450	1.1365	1.3815	0.0658	1.0901	1.1559	0.0000	2,350.8133	2,350.8133	0.4446	0.0000	2,360.1495
Total	3.6645	31.6449	21.7158	0.0346	2.3513	1.7129	3.5493	1.1757	1.6266	2.2778	0.0000	3,309.6669	3,309.6669	0.6983	0.0000	3,324.3300

Annual Unmitigated (lb/year except for CO2e which is metrict tons/year)

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-	Total CO2	CH4	N2O	CO2e
2016	0.3813	2.7264	2.0892	0.0033	0.0427	0.1684	0.2111	0.0122	0.1613	0.1735	0.0000	283.1063	283.1063	0.0559	0.0000	284.2792
2017	0.0026	0.0188	0.0152	0.0000	0.0002	0.0011	0.0014	0.0001	0.0011	0.0012	0.0000	2.1233	2.1233	0.0004	0.0000	2.1317
Total	0.3839	2.7452	2.1044	0.0033	0.0429	0.1695	0.2125	0.0123	0.1624	0.1747	0.0000	285.2296	285.2296	0.0563	0.0000	286.4109

Annual Mitigated (lb/year)

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-	Total CO2	CH4	N2O	CO2e
2016	0.3813	2.6078	2.0892	0.0033	0.0359	0.1684	0.2043	0.0100	0.1613	0.1712	0.0000	283.1060	283.1060	0.0559	0.0000	284.2790
2017	0.0026	0.0180	0.0152	0.0000	0.0002	0.0011	0.0014	0.0001	0.0011	0.0012	0.0000	2.1233	2.1233	0.0004	0.0000	2.1317
Total	0.3839	2.6258	2.1044	0.0033	0.0361	0.1695	0.2057	0.0100	0.1624	0.1724	0.0000	285.2293	285.2293	0.0563	0.0000	286.4107

SUMMARY OF CONSTRUCTION EMISSIONS OUTPUT FROM CALEEMOD

Peak Daily Criteria Construction Emissions per Control Equipment at Non-Refinery Facility

Description	ROG, lb/day	NOx, lb/day	CO, lb/day	SO2, lb/day	PM10 Total, lb/day	PM2.5 Total, lb/day
Daily Unmitigated	3.7	31.7	21.7	0.03	7.1	4.1
Daily Mitigated	3.7	31.7	21.7	0.03	3.5	2.3

Emissions estimated with CalEEMod for 2016.

Project Peak Daily Criteria Construction Emissions for Non-Refinery Facilities

Description	ROG, lb/day	NOx, lb/day	CO, lb/day	SO2, lb/day	PM10 Total, lb/day	PM2.5 Total, lb/day
Daily Unmitigated	40	349	239	0.38	78	45
Daily Mitigated	40	349	239	0.38	39	25

Emissions estimated with CalEEMod for 2016.
Assumed construction at all 11 non-refinery facilities could occur at the same time.
Assumed that facilties with multiple control equipment installation would occur in series, so the same daily number of construction equipment would be used, but over a longer period of time.

Greenhouse Gas Construction Emissions for Non-Refinery Facilities

CO2e per Piece of Control Equipment, metric ton/yr	Amoritized CO2e per Project, metric ton/yr
286	325

Emissions estimated with CalEEMod for 2016.
For project CO2e, the CO2e per facilty was multipled by the number of control equipment installed (i.e., 34 control equipment installed)

CONSTRUCTION FUEL USE

Diesel Fuel Use for Off-Road Construction Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor	Fuel Use by Piece of Equipment, gal/hr	Total Diesel Fuel Use, gal/day	Number of Days for Entire Project	Total Diesel Fuel Use, gal/project
Building Construction	Cranes	1	6.00	226	0.29	3.9	23.4	250	5,850
Building Construction	Aerial Lifts	1	8	62	0.31	1.2	9.6	250	2,400
Building Construction	Forklifts	1	6.00	89	0.20	1.1	6.6	250	1,650
Building Construction	Generator Sets	1	8.00	84	0.74	4.2	33.6	250	8,400
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37	2.1	12.6	250	3,150
Building Construction	Welders	2	8.00	46	0.45	NA		250	0
							85.8		**21,450**
Demolition	Cranes	1	8	226	0.29	3.9	31.2	10	312
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73	NA		10	0
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37	2.1	16.8	10	168
Demolition	Rubber Tired Dozers	1	8.00	255	0.40	5.9	47.2	10	472
							95.2		**952**
Paving	Cement and Mortar Mixers	1	6.00	9	0.56	2.8	16.8	5	84
Paving	Paving Equipment	1	8.00	130	0.36	2.8	22.4	5	112
Paving	Plate Compactors	1	6.00	125	0.42	2.8	16.8	5	84
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37	2.1	16.8	5	84
							72.8		**364**
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40	5.9	41.3	2	83
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37	2.1	16.8	2	34
Site Preparation	Trenchers	1	8	80	0.5	2.1	16.8	2	34
							74.9		149.8
Fuel use by equipment from Offroad for 2015						Max Daily Usage, gal/day	**95.2**		**21,450**

Fuel Use for On-Road Vehicles During Construction

Phase Name	Offroad Equipment Count	Worker Trip Number (gasoline)	Vendor Trip Number (diesel)	Hauling Trip Number (diesel)	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker, mpg	Vendor, mpg	Hauling, mpg	Worker Trip Fuel Use (gasoline), gal/day	Vendor Trip Fuel Use (diesel), gal/day	Hauling Trip Fuel Use (diesel), gal/day	Number of Days for Entire Project	Worker Trip Fuel Use (gasoline), gal/project	Vendor Trip Fuel Use (diesel), gal/project	Hauling Trip Fuel Use (diesel), gal/project
Demolition (Diesel)	3	15	0	5	14.7	6.9	20	19	12.2	8.9	23	0	22	10	232	0	225
Site Preparation (Diesel)	2	8	0	0	14.7	6.9	20	19	12.2	8.9	12	0	0	2	25	0	0
Building Construction (Gasoline)	6	18	7	0	14.7	6.9	20	19	12.2	8.9	28	8	0	250	6,963	1,980	0
Paving (Diesel)	4	13	0	0	14.7	6.9	20	19	12.2	8.9	20	0	0	5	101	0	0
											28	7.9	22		6,963	1,980	225

Fuel use by equipment from EMFAC2011 for 2015

Maximum Daily Fuel Use

Source	Gasoline, gal/day	Diesel Fuel, gal/day	Gasoline, gal/project	Diesel Fuel, gal/project
Construction Equipment	0	95	0	21,450
On-Road Vehicles	28	30	6,963	2,204
Total	28	126	6,963	23,654
Total for 11 facilities	306	1,381	76,595	260,197

CONSTRUCTION WATER USE

Construction Water Use for Dust Suppression (during construction - demolition/site prep)

Area Disturbed, acre	Area Disturbed, ft2	Depth of Water, ft	Water Use Area, ft3	Water Use, gal	Number of Washings	Total Daily Water Use, gal
0.28	12,272	0.005	61	459	3	1,377

Assumed 1/16 inch depth of water applied per washing

Construction Water Use for Hydrotesting (after construction is completed)

Facility Number	Nox Control Technology Assumed to Be Installed	Total Number of Units	Plot Space Needed Per Unit (sf)	plot space (sf) for all control equip	No. of NH3 storage tanks needed	Capacity of Storage Tank (gal)	Plot space (sf) needed per storage tank	Plot space (sf) needed for all storage tanks	Total plot space (sf) for all control equipment & chemical storage	Total acreage disturbed from Construction	Number of Tanks Overlapping Construction per day	Amount of Water Needed to Hydrotest during Overlap (gal/day)	Amount of Water Needed to Hydrotest for Entire Project (gal/project)
1	5 SCR - ICE, 3 SCR - turbine	8	176	1,408	2	3,000	400	800	2,208	0.05	2	6,000	6,000
2	6 SCR - ICE, 4 SCR - turbine	10	176	1,760	2	1,500	400	800	2,560	0.06	2	3,000	3,000
3	5 SCR	5	176	880	1	1,000	400	400	1,280	0.03	1	1,000	1,000
4	1 SCR	1	176	176	1	2,000	400	400	576	0.01	1	2,000	2,000
5	2 SCR	2	176	352	1	2,000	400	400	752	0.02	1	2,000	2,000
6	1 SCR	1	176	176	1	2,000	400	400	576	0.01	1	2,000	2,000
7	2 SCR	2	176	352	1	2,000	400	400	752	0.02	1	2,000	2,000
8	2 SCR	2	176	352	2	1,062	400	800	1,152	0.03	2	2,124	2,124
9	1 Tri-Mer	1	640	640	1	600	400	400	1,040	0.02	1	600	600
10	1 SCR	1	176	176	2	2,000	400	800	976	0.02	2	4,000	4,000
11	1 Replacement SCR	1	0	0	1	10,000	400	400	400	0.01	1	10,000	10,000
			Total	**6,272**	**15**	**27,162**	**4,400**	**6,000**	**12,272**	**0.28**	**15**	**34,724**	**34,724**

* replacement means that no additional plot space would be needed

OPERATION EMISSIONS SUMMARY

Non-Refinery Facility Operational Emissions

EMFAC2011 Emission Factors

Category	ROG	CO	NOx	SOx	PM10	PM2.5	CO2
Pass (lb/mile)	0.00056134	0.0052109	0.0004985	9.853E-06	0.0001047	4.469E-05	0.8632853
Deliv (lbmile)	0.00032992	0.0015858	0.0097493	1.729E-05	0.0004209	0.0002564	1.7665728
HHDT-DSL (lb/mile)	0.00035162	0.0014927	0.009812	2.383E-05	0.0005717	0.000367	2.435248

EMFAC2011 Emission Factors for 2015 fleet

Heavy-duty Truck Trips

Description	NH3/Urea Number of Delivery Trips	Adsorbent Number of Delivery Trips	Solid Waste Number of Haul Trips	Filter Waste Number of Haul Trips	Catalyst Number of Delivery Trips	Total Heavy Duty Truck Trips
Annual	437	5	11	1	11	465
Peak Day	11	1	1	1	11	25

Adsorbent, solid waste and filter waste based on vendor calcs for SOx portion of Ultracat system
One catalyst delivery trips per facilty was assumed.
Peak day assumed one ammonia/urea delivery occurs at each non-refinery facility and adsorbent, solid waste and haul trip occurs on same day.

Peak Day

Vehicle Type	No of Trips	Distance, mile/trip	ROG, lb/day	CO, lb/day	NOx, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day	Total Miles Per Day	Total Gallons Per Day
Heavy Duty Truck	25	100	0.88	3.73	24.5	0.06	1.43	0.92	2,500	511
Medium Duty Truck	11	80	0.29	1.40	8.58	0.02	0.37	0.23	880	99
			1.17	**5.13**	**33.1**	**0.07**	**1.80**	**1.14**	**3,380**	**610**

Assumed one tech trip for control system mantainance occurs at each of the ten non-refinery facilities
Default truck trips were assumed to 80 miles round trip. Ammonia deliveries were assumed to be 100 miles round trip.

OPERATION EMISSIONS SUMMARY

Annual

Vehicle Type	No of Trips	Distance, mile/trip	CO_2, metric ton/yr	Total Miles Per Year	Total Gallons Per Year
Heavy Duty Truck	465	100	51	46,536	9,517
Medium Duty Truck	286	80	25	22,880	2,574
			77	**69,416**	**12,090**

Assumed one tech trip every other week for control system mantainance occurs at each of the 11 non-refinery facilities
Default truck trips were assumed to 80 miles round trip. Ammonia deliveries were assumed to be 100 miles round trip.

Operations - Criteria Pollutants From Electricity Generation

Operation	Peak Daily Electricity Demand	Simple Cycle Turbine Emission Factors					
Electricity Generation		VOC (lb/MWh)	CO (lb/MWh)	NOx (lb/MWh)	SOx (lb/MWh)	PM10 (lb/MWh)	PM2.5 (lb/MWh)
Electricity Needed by 11 Non-Refineries	45	0.02	0.08	0.09	0.00	0.06	0.06

Incremental Increase in Criteria Pollutant Emissions from Electricty Generation	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Emissions from Electricity Needed by 11 Non-Refineries	0.91	3.63	4.08	0.00	2.72	2.67
TOTAL	1	4	4	0	3	3

Example Calculation: NOx: 0.09 lbs/MWh x 45.3 MWh = 4.08 lbs

OFFSITE CONSEQUENCE ANALYSIS

Offsite Consequence Input Data for NH3 spill of one 5,000 gallon storage tank at a non-refinery facility

Non-Refinery

Ammonia Storage, gal	Berm Capacity, gal	Ammonia Berm, ft3	Height of Berm, ft	Area, ft2
5,000	5,500	735	3.0	245

Berms must be able to contain 110% the volume of the tank
Typical berm heights are three feet tall.

AMMONIA SLIP CALCULATION

Ammonia Slip Estimate For Non-Refinery Facilities

Ammonia Slip Conc at the Exit of the Stack, ppm	Dispersion Factor	Molecular Weight, g/mol	Peak Conc at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index	Chronic Hazard Index
5	0.01	17.03	35	3,200	200	0.01	0.17

Ammonia slip is subject to a permit limit of 5 ppm.
Conc., ug/m3 = (conc., ppm x 1,000 x molecular weight, g/mol)/24.5 m3/kmol

Based on the Staff Report for Toxic Air Contaminants 1401.1 – Requirements for New and Relocated Facilities Near Schools, and 1402 – Control of Toxic Air Contaminants from Existing Source, June 2015 the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack.

Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

DIESEL IDLING HEALTH RISK ASSESSMENT

Non-Refinery - Diesel Idling Emissions

Facility 8 has the peak annual trips per year = 123 +26 tech trips (bi-weekly)=149 total trips

EF, g/hr	Annual No of Trips	Idling, h/y	Emisions, lb/yr	Emisions, ton/yr
1.67	149	37.267448	0.14	6.88E-05

Heavy-duty idling rates from emfac2011 idling emission rates.xlsx (http://www.arb.ca.gov/msei/emfac2011 idling emission rates.xlsx).

Emisions, ton/yr	Cancer Potency Factor, (mg/kg-d)-1	X/Q at 25 m, (ug/m3)/(ton/yr)	CEF	MP	MWHF	Carcinogenic Health Risk	Screening Level	Significant?
6.88E-05	1.1	29.64	676.63	1	1	1.52E-06	1.00E-05	NO

Carcinogenic health risk = emissions, ton/yr x cancer potency, (mg/kg-day)-1 x X/Q, (ug/m3)/(ton/yr) x CEF x MP x MWHF

RMP*Comp

RMP*Comp

Back

Estimated Distance Calculation

Estimated distance to toxic endpoint: <0.1 miles (<0.16 kilometers); report as 0.1 mile

This is the downwind distance to the toxic endpoint specified for this regulated substance under the RMP Rule. Report all distances shorter than 0.1 mile as 0.1 mile, and all distances longer than 25 miles as 25 miles.

Scenario Summary

Chemical:	Ammonia (water solution)
Initial concentration:	20 %
CAS number:	7664-41-7
Threat type:	Toxic Liquid
Scenario type:	Worst-case
Liquid temperature:	25 C
Quantity released:	5500 gallons
Mitigation measures:	
Diked area:	245 square feet
Dike height:	3 feet
Release rate to outside air:	5.3 pounds per minute
Surrounding terrain type:	Urban surroundings (many obstacles in the immediate area)
Toxic endpoint:	0.14 mg/L; basis: ERPG-2

Assumptions about this scenario

Wind speed:	1.5 meters/second (3.4 miles/hour)
Stability class:	F
Air temperature:	77 degrees F (25 degrees C)

CalEEMod Input Data

Project Characteristics

ProjectName	Location Scope	EMFAC_ID	WindSpeed	Precipitation Frequency	Climate Zone	Urbanization level	Operational Year	UtilityCompany	CO2IntensityFactor	CH4Intensity Factor	N2OIntensity Factor	TotalPopulation	TotalLotAcreage	UsingHistorical EnergyUseData
RECLAIM	AD	SCAQMD	2.2	31	8	Urban	2015	Los Angeles Department of Water & Power	1227.89	0.029	0.006	0	1	0

Pollutants

PollutantSelection		PollutantFullName	PollutantName
	1	Reactive Organic Gases (ROG)	ROG
	1	Nitrogen Oxides (NOx)	NOX
	1	Carbon Monoxide (CO)	CO
	1	Sulfur Dioxide (SO2)	SO2
	1	Particulate Matter 10um (PM10)	PM10
	1	Particulate Matter 2.5um (PM2.5)	PM2_5
	1	Fugitive PM10um (PM10)	PM10_FUG
	1	Fugitive PM2.5um (PM2.5)	PM25_FUG
	1	Biogenic Carbon Dioxide (CO2)	CO2_BIO
	1	Non-Biogenic Carbon Dioxide (CO2)	CO2_NBIO
	1	Carbon Dioxide (CO2)	CO2
	1	Methane (CH4)	CH4
	1	Nitrous Oxide (N2O)	N2O
	1	CO2 Equivalent GHGs (CO2e)	CO2E

Land Use

LandUseType	LandUseSubType	LandUseUnitAmount	LandUseSizeMetric	LotAcreage	LandUseSquareFeet	Population
Industrial	General Heavy Industry	43.56	1000sqft	1	43560	0

Construction Phase

PhaseNumber	PhaseName	PhaseType	PhaseStartDate	PhaseEndDate	NumDaysWeek	NumDays	PhaseDescription
1	Demolition	Demolition	2016/01/01	2016/01/14	5	10	
2	Site Preparation	Site Preparation	2016/01/15	2016/01/18	5	2	
3	Building Construction	Building Construction	2016/01/20	2017/01/03	5	250	
4	Paving	Paving	2016/06/08	2016/06/14	5	5	

OffRoad Equipment

PhaseName	OffRoadEquipmentType	OffRoadEquipmentUnitAmount	UsageHours	HorsePower	LoadFactor
Demolition	Concrete/Industrial Saws	1	8	81	0.73
Demolition	Cranes	1	8	226	0.29
Demolition	Rubber Tired Dozers	1	8	255	0.4
Demolition	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation Site	Rubber Tired Dozers	1	7	255	0.4
Preparation Site	Tractors/Loaders/Backhoes	1	8	97	0.37
Preparation Building	Trenchers	1	8	80	0.5
Construction Building	Aerial Lifts	1	8	62	0.31
Construction Building	Cranes	1	6	226	0.29
Construction Building	Forklifts	1	6	89	0.2
Construction Building	Generator Sets	1	8	84	0.74
Construction Building	Tractors/Loaders/Backhoes	1	6	97	0.37
Construction	Welders	2	8	46	0.45
Paving	Cement and Mortar Mixers	1	6	9	0.56
Paving	Paving Equipment	1	8	130	0.36
Paving	Plate Compactors Tractors/	1	6	125	0.42
Paving	Loaders/Backhoes	1	8	97	0.37

Trips and VMT

PhaseName	WorkerTripNumber	VendorTripNumber	HaulingTripNumber	WorkerTripLength	VendorTripLength	HaulingTripLength	WorkerVehicleClass	VendorVehicleClass	HaulingVehicleClass
Demolition	15	0	49	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT
Site Preparation	8	0	0	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT
Building Construction	18	7	0	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT
Paving	13	0	0	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT

OnRoad Dust

PhaseName	WorkerPercentPave	VendorPercentPave	HaulingPercentPave	RoadSiltLoading	MaterialSiltContent	MaterialMoistureContent	AverageVehicleWeight	MeanVehicleSpeed
Demolition	100	100	100	0.1	8.5	0.5	2.4	40
Site Preparation	100	100	100	0.1	8.5	0.5	2.4	40
Building Construction	100	100	100	0.1	8.5	0.5	2.4	40
Paving	100	100	100	0.1	8.5	0.5	2.4	40

Demolition

PhaseName	DemolitionSizeMetric	DemolitionUnitAmount
Demolition	Ton of Debris	500

Grading

PhaseName	Material Imported	Material Exported	Grading Size Metric	Import Export Phased	Mean Vehicle Speed	Acres Of Grading	Material Moisture Content Bulldozing	Material Moisture Content Truck Loading	Material Silt Content
Site Preparation	0	0		0	7.1	1	7.9	12	6.9

Architectural Coatings

PhaseName	Architectural CoatingStart Date	Architectural CoatingEnd Date	EF_Residential _Interior	ConstArea_ Residential _Interior	EF_Residential _Exterior	ConstArea_ Residential_ Exterior	EF_Nonresidential _Interior	ConstArea_ Nonresidential _Interior	EF_Nonresidential _Exterior	ConstArea_ Nonresidential_ Exterior

Paving

ParkingLotAcreage

Vehicle Trips

Vehicle Trips Land Use SubType	Vehicle Trips Land Use Size Metric	WD_TR	ST_TR	SU_TR	HW_TL	HS_TL	HO_TL	CC_TL	CW_TL	CNW_TL	PR_TP	DV_TP	PB_TP	HW_TTP	HS_TTP	HO_TTP	CC_TTP	CW_TTP	CNW_TTP
General Heavy Industry	1000 sqft	1.5	1.5	1.5	0	0	0	8.4	16.6	6.9	92	5	3	0	0	0	28	59	13

Vehicle Emission Factors

Season	EmissionType	LDA	LDT1	LDT2	MDV	LHD1	LHD2
A	FleetMix	0.514499	0.060499	0.179997	0.139763	0.042095	0.006675
A	CH4_IDLEX	0	0	0	0	0.001309	0.001023
A	CH4_RUNEX	0.013984	0.029514	0.019657	0.030056	0.016394	0.011954
A	CH4_STREX	0.010839	0.025416	0.014671	0.025703	0.02727	0.017952
A	CO_IDLEX	0	0	0	0	0.190064	0.152757
A	CO_RUNEX	1.233474	3.189989	1.739629	2.486494	1.63021	1.189601
A	CO_STREX	2.353874	5.693141	3.413938	5.206356	5.255995	3.391635
A	CO2_NBIO_IDLEX	0	0	0	0	8.332614	9.178367
A	CO2_NBIO_RUNEX	308.2126	363.471	438.8062	569.4004	576.1965	555.2706
A	CO2_NBIO_STREX	64.82983	75.69049	91.13311	117.9521	44.55575	30.72628
A	NOX_IDLEX	0	0	0	0	0.045728	0.09691
A	NOX_RUNEX	0.110055	0.312796	0.203818	0.320636	1.416374	2.274808
A	NOX_STREX	0.159103	0.327401	0.327752	0.506279	1.457145	0.977107
A	PM10_IDLEX	0	0	0	0	0.000488	0.001068
A	PM10_PMBW	0.03675	0.03675	0.03675	0.03675	0.046153	0.062741
A	PM10_PMTW	0.008	0.008	0.008	0.008	0.008948	0.009983
A	PM10_RUNEX	0.002056	0.004908	0.002107	0.002358	0.008642	0.016542
A	PM10_STREX	0.002808	0.005384	0.002799	0.003289	0.00141	0.000939
A	PM25_IDLEX	0	0	0	0	0.000449	0.000982
A	PM25_PMBW	0.01575	0.01575	0.01575	0.01575	0.01978	0.026889
A	PM25_PMTW	0.002	0.002	0.002	0.002	0.002237	0.002496
A	PM25_RUNEX	0.001881	0.004504	0.001933	0.002168	0.007953	0.015216
A	PM25_STREX	0.002568	0.004943	0.002573	0.003029	0.001291	0.000844
A	ROG_DIURN	0.066402	0.189701	0.077836	0.089694	0.003055	0.001955
A	ROG_HTSK	0.14692	0.32917	0.168393	0.195309	0.076216	0.052279
A	ROG_IDLEX	0	0	0	0	0.030443	0.023575
A	ROG_RESTL	0.054554	0.136894	0.066595	0.080483	0.001725	0.001108
A	ROG_RUNEX	0.035351	0.097338	0.044946	0.071591	0.116884	0.109968
A	ROG_RUNLS	0.329804	1.166493	0.541766	0.61118	0.445414	0.299477
A	ROG_STREX	0.18834	0.445148	0.257689	0.452871	0.480847	0.313738
A	SO2_IDLEX	0	0	0	0	0.000088	0.000094
A	SO2_RUNEX	0.003609	0.00417	0.004911	0.006213	0.005871	0.005586
A	SO2_STREX	0.000776	0.000943	0.00106	0.001357	0.000554	0.000378
A	TOG_DIURN	0.066402	0.189701	0.077836	0.089694	0.003055	0.001955
A	TOG_HTSK	0.14692	0.32917	0.168393	0.195309	0.076216	0.052279
A	TOG_IDLEX	0	0	0	0	0.03235	0.025262
A	TOG_RESTL	0.054554	0.136894	0.066595	0.080483	0.001725	0.001108
A	TOG_RUNEX	0.049912	0.128354	0.065324	0.102752	0.13759	0.128711
A	TOG_RUNLS	0.329804	1.166493	0.541766	0.61118	0.445414	0.299477
A	TOG_STREX	0.201307	0.475598	0.275275	0.483697	0.513556	0.335238
S	FleetMix	0.514499	0.060499	0.179997	0.139763	0.042095	0.006675
S	CH4_IDLEX	0	0	0	0	0.001309	0.001023
S	CH4_RUNEX	0.013984	0.029514	0.019657	0.030056	0.016394	0.011954
S	CH4_STREX	0.010839	0.025416	0.014671	0.025703	0.02727	0.017952
S	CO_IDLEX	0	0	0	0	0.190064	0.152756
S	CO_RUNEX	1.350882	3.453577	1.905978	2.728272	1.656744	1.198792
S	CO_STREX	1.868119	4.517537	2.699157	4.111903	4.259587	2.777588
S	CO2_NBIO_IDLEX	0	0	0	0	8.332614	9.178367
S	CO2_NBIO_RUNEX	324.0649	381.2572	460.7961	598.4716	576.1965	555.2706
S	CO2_NBIO_STREX	64.82983	75.69049	91.13311	117.9521	44.55575	30.72628
S	NOX_IDLEX	0	0	0	0	0.045728	0.09691
S	NOX_RUNEX	0.09727	0.274387	0.179725	0.283025	1.31395	2.138796
S	NOX_STREX	0.147973	0.30427	0.304804	0.470634	1.401942	0.940016
S	PM10_IDLEX	0	0	0	0	0.000488	0.001068

Season	EmissionType	LDA	LDT1	LDT2	MDV	LHD1	LHD2
S	PM10_PMBW	0.03675	0.03675	0.03675	0.03675	0.046153	0.062741
S	PM10_PMTW	0.008	0.008	0.008	0.008	0.008948	0.009983
S	PM10_RUNEX	0.002056	0.004908	0.002107	0.002358	0.008642	0.016542
S	PM10_STREX	0.002808	0.005384	0.002799	0.003289	0.00141	0.000939
S	PM25_IDLEX	0	0	0	0	0.000449	0.000982
S	PM25_PMBW	0.01575	0.01575	0.01575	0.01575	0.01978	0.026889
S	PM25_PMTW	0.002	0.002	0.002	0.002	0.002237	0.002496
S	PM25_RUNEX	0.001881	0.004504	0.001933	0.002168	0.007953	0.015216
S	PM25_STREX	0.002568	0.004943	0.002573	0.003029	0.001291	0.000844
S	ROG_DIURN	0.106937	0.310496	0.126009	0.146254	0.004832	0.00306
S	ROG_HTSK	0.155669	0.358306	0.179941	0.208545	0.082417	0.056164
S	ROG_IDLEX	0	0	0	0	0.030443	0.023575
S	ROG_RESTL	0.084087	0.217884	0.102674	0.124565	0.002767	0.001756
S	ROG_RUNEX	0.036348	0.100738	0.046745	0.075462	0.119071	0.110744
S	ROG_RUNLS	0.31515	1.093856	0.508247	0.577209	0.436118	0.291869
S	ROG_STREX	0.160037	0.378639	0.2195	0.385076	0.425075	0.277672
S	SO2_IDLEX	0	0	0	0	0.000088	0.000094
S	SO2_RUNEX	0.003797	0.004379	0.00516	0.006534	0.005871	0.005587
S	SO2_STREX	0.000767	0.000922	0.001048	0.001338	0.000536	0.000367
S	TOG_DIURN	0.106937	0.310496	0.126009	0.146254	0.004832	0.00306
S	TOG_HTSK	0.155669	0.358306	0.179941	0.208545	0.082417	0.056164
S	TOG_IDLEX	0	0	0	0	0.03235	0.025262
S	TOG_RESTL	0.084087	0.217884	0.102674	0.124565	0.002767	0.001756
S	TOG_RUNEX	0.051697	0.132929	0.068158	0.107954	0.14002	0.129611
S	TOG_RUNLS	0.31515	1.093856	0.508247	0.577209	0.436118	0.291869
S	TOG_STREX	0.17106	0.404544	0.234481	0.41129	0.453984	0.29669
W	FleetMix	0.514499	0.060499	0.179997	0.139763	0.042095	0.006675
W	CH4_IDLEX	0	0	0	0	0.001309	0.001023
W	CH4_RUNEX	0.013984	0.029514	0.019657	0.030056	0.016394	0.011954
W	CH4_STREX	0.010839	0.025416	0.014671	0.025703	0.02727	0.017952
W	CO_IDLEX	0	0	0	0	0.190064	0.152756
W	CO_RUNEX	1.193516	3.100688	1.684197	2.407556	1.624424	1.186618
W	CO_STREX	2.433359	5.864449	3.527735	5.365933	5.306769	3.437683
W	CO2_NBIO_IDLEX	0	0	0	0	8.332614	9.178367
W	CO2_NBIO_RUNEX	303.2743	358.1429	432.0299	560.7637	576.1965	555.2706
W	CO2_NBIO_STREX	64.82983	75.69049	91.13311	117.9521	44.55575	30.72628
W	NOX_IDLEX	0	0	0	0	0.045728	0.09691
W	NOX_RUNEX	0.106433	0.302816	0.197086	0.309883	1.388776	2.234735
W	NOX_STREX	0.161047	0.33106	0.331685	0.511887	1.462705	0.981562
W	PM10_IDLEX	0	0	0	0	0.000488	0.001068
W	PM10_PMBW	0.03675	0.03675	0.03675	0.03675	0.046153	0.062741
W	PM10_PMTW	0.008	0.008	0.008	0.008	0.008948	0.009983
W	PM10_RUNEX	0.002056	0.004908	0.002107	0.002358	0.008642	0.016542
W	PM10_STREX	0.002808	0.005384	0.002799	0.003289	0.00141	0.000939
W	PM25_IDLEX	0	0	0	0	0.000449	0.000982
W	PM25_PMBW	0.01575	0.01575	0.01575	0.01575	0.01978	0.026889
W	PM25_PMTW	0.002	0.002	0.002	0.002	0.002237	0.002496
W	PM25_RUNEX	0.001881	0.004504	0.001933	0.002168	0.007953	0.015216
W	PM25_STREX	0.002568	0.004943	0.002573	0.003029	0.001291	0.000844
W	ROG_DIURN	0.067842	0.198859	0.078401	0.089081	0.003369	0.002144
W	ROG_HTSK	0.166957	0.383619	0.189492	0.216372	0.089406	0.061396
W	ROG_IDLEX	0	0	0	0	0.030443	0.023575
W	ROG_RESTL	0.053212	0.133717	0.064685	0.078352	0.001771	0.001126
W	ROG_RUNEX	0.0349	0.095978	0.044277	0.07031	0.116392	0.109768
W	ROG_RUNLS	0.370102	1.380262	0.6353	0.711159	0.483048	0.326354
W	ROG_STREX	0.192428	0.453488	0.263055	0.461497	0.485385	0.317378
W	SO2_IDLEX	0	0	0	0	0.000088	0.000094

Season	EmissionType	LDA	LDT1	LDT2	MDV	LHD1	LHD2
W	SO2_RUNEX	0.00355	0.004108	0.004834	0.006118	0.005871	0.005586
W	SO2_STREX	0.000777	0.000946	0.001062	0.00136	0.000555	0.000379
W	TOG_DIURN	0.067842	0.198859	0.078401	0.089081	0.003369	0.002144
W	TOG_HTSK	0.166957	0.383619	0.189492	0.216372	0.089406	0.061396
W	TOG_IDLEX	0	0	0	0	0.03235	0.025262
W	TOG_RESTL	0.053212	0.133717	0.064685	0.078352	0.001771	0.001126
W	TOG_RUNEX	0.049222	0.126641	0.064347	0.101088	0.137046	0.128482
W	TOG_RUNLS	0.370102	1.380262	0.6353	0.711159	0.483048	0.326354
W	TOG_STREX	0.205676	0.484505	0.281005	0.492909	0.518404	0.339126

MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098
0.007624	0.024528	0.018472	0	0	0.005424	0
0.005872	0.01213	0.003081	0	0	0.007712	0
0	0	0	0	0	0	0
1.836153	2.871608	2.240681	0	0	1.05372	0
1.373582	1.934274	1.632938	5.524531	23.49551	5.135838	5.101083
21.33276	64.36907	11.40941	10.8845	9.784148	34.38519	9.556879
608.9204	571.3243	576.1996	0	0	576.1853	0
998.2352	1662.82	1089.859	2143.366	146.8008	1136.116	657.208
59.23662	62.55469	37.01571	29.69639	44.88682	130.6133	32.33925
6.682209	5.33745	6.457943	0	0	8.137056	0
3.731903	6.93817	4.826998	13.19486	1.191712	8.334269	1.761286
2.187072	3.901161	1.538267	1.232285	0.306462	2.274502	0.900295
0.02811	0.022337	0.022314	0	0	0.02741	0
0.11256	0.060052	0.094097	0.679664	0.036749	0.574428	0.050551
0.01124	0.03473	0.010451	0.008	0.008	0.011038	0.00859
0.093253	0.121195	0.063139	0.209684	0.000578	0.088393	0.029094
0.003758	0.003922	0.001248	0.000836	0.001854	0.00737	0.00179
0.025861	0.02055	0.020529	0	0	0.025217	0
0.04824	0.025737	0.040327	0.291285	0.01575	0.246184	0.021665
0.00281	0.008682	0.002613	0.002	0.002	0.002759	0.002147
0.085789	0.111499	0.058087	0.192889	0.000467	0.081246	0.026727
0.003176	0.003151	0.001076	0.000743	0.001467	0.006316	0.001546
0.003664	0.002617	0.001084	0.005873	0.999598	0.040185	1.405902
0.148396	0.146196	0.030425	0.104047	0.47086	0.287265	0.090027
0.16415	0.528083	0.397688	0	0	0.116768	0
0.002103	0.001662	0.000524	0.00321	0.572527	0.016957	0.543208
0.168477	0.274802	0.16882	0.826002	2.51152	0.436072	0.164067
0.617851	0.571991	0.308148	0.717582	1.628305	2.250725	2.067505
1.440778	2.38542	0.73497	0.796077	2.134906	2.363626	0.588984
0.005958	0.00559	0.005638	0	0	0.005638	0
0.009834	0.016287	0.010788	0.021114	0.001953	0.011277	0.00674
0.000987	0.001726	0.000581	0.0005	0.000681	0.001952	0.0005
0.003664	0.002617	0.001084	0.005873	0.999598	0.040185	1.405902
0.148396	0.146196	0.030425	0.104047	0.47086	0.287265	0.090027
0.186873	0.601183	0.452737	0	0	0.132932	0
0.002103	0.001662	0.000524	0.00321	0.572527	0.016957	0.543208
0.193707	0.313538	0.197872	0.920387	2.755048	0.485774	0.196115
0.617851	0.571991	0.308148	0.717582	1.628305	2.250725	2.067505
1.542818	2.556696	0.785914	0.850607	2.295552	2.530875	0.630464
0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098
0.007185	0.023116	0.017408	0	0	0.005111	0
0.005872	0.01213	0.003081	0	0	0.007712	0
0	0	0	0	0	0	0
1.334224	2.086629	1.628171	0	0	0.765677	0
1.380654	1.944328	1.656457	5.55465	22.68424	5.105164	5.148108
17.58779	53.89139	9.346911	9.183033	8.738903	29.5561	7.621596
645.0974	605.2676	610.4325	0	0	610.4175	0
998.2352	1662.82	1089.859	2143.366	146.8008	1136.116	657.208
59.23662	62.55469	37.01571	29.69639	44.88682	130.6133	32.33925
6.897161	5.509144	6.665681	0	0	8.398808	0
3.508187	6.557672	4.535044	12.42909	1.036711	7.838125	1.607728
2.099169	3.74208	1.476893	1.177907	0.290277	2.150793	0.864345
0.023696	0.01883	0.018811	0	0	0.023107	0

MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.11256	0.060052	0.094097	0.679664	0.036749	0.574428	0.050551
0.01124	0.03473	0.010451	0.008	0.008	0.011038	0.00859
0.093253	0.121195	0.063139	0.209684	0.000578	0.088393	0.029094
0.003758	0.003922	0.001248	0.000836	0.001854	0.00737	0.00179
0.021801	0.017324	0.017306	0	0	0.021258	0
0.04824	0.025737	0.040327	0.291285	0.01575	0.246184	0.021665
0.00281	0.008682	0.002613	0.002	0.002	0.002759	0.002147
0.085789	0.111499	0.058087	0.192889	0.000467	0.081246	0.026727
0.003176	0.003151	0.001076	0.000743	0.001467	0.006316	0.001546
0.005753	0.004301	0.001692	0.008697	1.700317	0.061434	2.183595
0.155025	0.151308	0.031846	0.107985	0.561483	0.292874	0.094741
0.154696	0.497669	0.374783	0	0	0.110043	0
0.003374	0.002841	0.000815	0.00494	1.085294	0.026954	0.872502
0.169056	0.275038	0.169948	0.834999	2.434698	0.437395	0.164617
0.603843	0.566792	0.301618	0.672654	1.535435	2.074873	2.031341
1.250518	2.040298	0.647208	0.713405	1.867254	2.084582	0.497069
0.006312	0.005923	0.005973	0	0	0.005973	0
0.009834	0.016287	0.010788	0.021114	0.001938	0.011277	0.006741
0.000922	0.001551	0.000546	0.000471	0.000656	0.001867	0.000466
0.005753	0.004301	0.001692	0.008697	1.700317	0.061434	2.183595
0.155025	0.151308	0.031846	0.107985	0.561483	0.292874	0.094741
0.17611	0.566558	0.426662	0	0	0.125276	0
0.003374	0.002841	0.000815	0.00494	1.085294	0.026954	0.872502
0.194354	0.313797	0.19914	0.929912	2.674178	0.487223	0.196917
0.603843	0.566792	0.301618	0.672654	1.535435	2.074873	2.031341
1.338953	2.186635	0.692039	0.762252	2.007642	2.231743	0.53206
0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098
0.008231	0.026479	0.019941	0	0	0.005855	0
0.005872	0.01213	0.003081	0	0	0.007712	0
0	0	0	0	0	0	0
2.529293	3.955628	3.086528	0	0	1.451495	0
1.370893	1.931917	1.623723	5.51775	23.372	5.120318	5.084938
21.7725	65.0873	11.62499	11.02551	9.827199	35.31001	9.600634
558.9618	524.4502	528.9255	0	0	528.9124	0
998.2352	1662.82	1089.859	2143.366	146.8008	1136.116	657.208
59.23662	62.55469	37.01571	29.69639	44.88682	130.6133	32.33925
6.38537	5.100348	6.171066	0	0	7.77559	0
3.662149	6.824618	4.73854	12.9417	1.159392	8.195525	1.722599
2.201793	3.919972	1.547748	1.239148	0.308334	2.301931	0.903018
0.034204	0.027179	0.027152	0	0	0.033352	0
0.11256	0.060052	0.094097	0.679664	0.036749	0.574428	0.050551
0.01124	0.03473	0.010451	0.008	0.008	0.011038	0.00859
0.093253	0.121195	0.063139	0.209684	0.000578	0.088393	0.029094
0.003758	0.003922	0.001248	0.000836	0.001854	0.00737	0.00179
0.031467	0.025005	0.02498	0	0	0.030684	0
0.04824	0.025737	0.040327	0.291285	0.01575	0.246184	0.021665
0.00281	0.008682	0.002613	0.002	0.002	0.002759	0.002147
0.085789	0.111499	0.058087	0.192889	0.000467	0.081246	0.026727
0.003176	0.003151	0.001076	0.000743	0.001467	0.006316	0.001546
0.00411	0.002907	0.001186	0.006858	1.127888	0.047474	1.666334
0.182742	0.187402	0.035009	0.132355	0.623192	0.361068	0.118237
0.177206	0.570084	0.429318	0	0	0.126055	0
0.002194	0.001738	0.00054	0.003517	0.567437	0.01842	0.588696
0.168308	0.274748	0.168506	0.824141	2.514867	0.43494	0.163868
0.668492	0.609357	0.329156	0.83574	1.898047	2.652978	2.181787
1.465078	2.415535	0.742361	0.805192	2.153808	2.416549	0.593399
0.005469	0.005132	0.005176	0	0	0.005175	0

MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.009833	0.016287	0.010788	0.021113	0.001952	0.011277	0.00674
0.000995	0.001738	0.000585	0.000503	0.000683	0.001968	0.000501
0.00411	0.002907	0.001186	0.006858	1.127888	0.047474	1.666334
0.182742	0.187402	0.035009	0.132355	0.623192	0.361068	0.118237
0.201735	0.648997	0.488745	0	0	0.143505	0
0.002194	0.001738	0.00054	0.003517	0.567437	0.01842	0.588696
0.193521	0.313479	0.197524	0.918421	2.75856	0.484571	0.195866
0.668492	0.609357	0.329156	0.83574	1.898047	2.652978	2.181787
1.568829	2.588987	0.793772	0.860354	2.315874	2.587544	0.635197

Road Dust

RoadPercentPave	RoadSiltLoading	MaterialSiltContent	MaterialMoistureContent	MobileAverageVehicleWeight	MeanVehicleSpeed
100	0.1	4.3	0.5	2.4	40

Woodstoves

WoodstovesLandUseSubType	NumberConventional	NumberCatalytic	NumberNoncatalytic	NumberPellet	WoodstoveDayYear	WoodstoveWoodMass

Woodstoves

WoodstovesLandUseSubType	NumberConventional	NumberCatalytic	NumberNoncatalytic	NumberPellet	WoodstoveDayYear	WoodstoveWoodMass

ROG_EF
1.98E-05

Area_EF_Residential_Interior	Area_Residential_Interior	Area_EF_Residential_Exterior	Area_Residential_Exterior	Area_EF_Nonresidential_Interior	Area_Nonresidential_Interior	Area_EF_Nonresidential_Exterior	Area_Nonresidential_Exterior	ReapplicationRatePercent
50	0	100	0	250	65340	250	21780	10

NumberSnowDays	NumberSummerDays
0	250

EnergyUseLandUseSubType	T24E	NT24E	LightingElect	T24NG	NT24NG
General Heavy Industry	1.99	3.83	3.42	14.78	6.86

Water Land Use Sub Type	Water Land Use Size Metric	Indoor Water Use Rate	Outdoor Water Use Rate	Electricity Intensity Factor To Supply	Electricity Intensity Factor To Treat	Electricity Intensity Factor To Distribute	Electricity Intensity Factor For Wastewater Treatment	Septic Tank Percent	Aerobic Percent	Anaerobic and Facultative Lagoons Percent	AnaDigest Comb Digest Gas Percent	AnaDigest Cogen Comb Digest Gas Percent
General Heavy Industry	1000sqft	10073250	0	9727	111	1272	1911	10.33	87.46	2.21	100	0

SolidWasteLandUseSubType	SolidWasteLandUseSizeMetric	SolidWasteGenerationRate	LandfillNoGasCapture	LandfillCaptureGasFlare	LandfillCaptureGasEnergyRecovery
General Heavy Industry	1000sqft	54.01	6	94	0

VegetationLandUseType	VegetationLandUseSubType	AcresBegin	AcresEnd	CO2peracre

BroadSpeciesClass	NumberOfNewTrees	CO2perTree

	FuelType	Tier	NumberOfEquipmentMitigated	TotalNumberOfEquipmentMitigated	DPF	OxidationCatalyst
ConstMitigationEquipmentType	Diesel	No Change	0	1	No Change	0
Cement and Mortar Mixers	Diesel	No Change	0	1	No Change	0
Concrete/Industrial Saws	Diesel	No Change	0	1	No Change	0
Cranes	Diesel	No Change	0	1	No Change	0
Forklifts	Diesel	No Change	0	1	No Change	0
Generator Sets	Diesel	No Change	0	1	No Change	0
Paving Equipment	Diesel	No Change	0	1	No Change	0
Plate Compactors	Diesel	No Change	0	2	No Change	0
Rubber Tired Dozers Tractors/	Diesel	No Change	0	4	No Change	0
Loaders/Backhoes Welders	Diesel	No Change	0	2	No Change	0

SoilStabilizerC	SoilStabilizerPl	SoilStabilizerPl	ReplaceGround	ReplaceGround	ReplaceGround	WaterExposed	WaterExposed	WaterExposed	WaterExposed	WaterUnpaved	WaterUnpaved	WaterUnpaved	WaterUnpaved	CleanPavedRoadPercentReduction
0	0	0	0	0	0	1	3	61	61	0	0	0	0	0

Project Setting	Increase Density Check	Increase Density DU Per Acre	Increase Density Job Per Acre	Increase Diversity Check	Improve Walkability Design Check	Improve Walkability Design Intersections	Improve Destination Accessibility Check	Improve Destination Accessibility Distance

Increase Transit Accessibility Check	Increase Transit Accessibility Distance	Integrate Below Market Rate Housing Check	Integrate Below Market Rate Housing DU	Improve Pedestrian Network Check	Improve Pedestrian Network Selection	Provide Traffic Calming Measures Check	Provide Traffic Calming Measures Percent Street	Provide Traffic Calming Measures Percent Intersection

Implement NEV Network Check	Implement NEV Network Number	Limit Parking Supply Check	Limit Parking Supply Space Percent Reduction	Unbundle Parking Cost Check	Unbundle Parking Cost Cost	OnStreet Market Pricing Check	OnStreet Market Pricing Price Percent Increase	Provide BRT System Check

Provide BRT System Percent BRT	Expand Transit Network Check	Expand Transit Network Transit Coverage Percent Increase	Increase Transit Frequency Check	Increase Transit Frequency Implementation Level	Increase Transit Frequency Headways Percent Reduction

ImplementTrip	ImplementTrip	ImplementTrip	TransitSubsidy	TransitSubsidy	TransitSubsidy	ImplementEmp	ImplementEmp	WorkplacePark	WorkplacePark	WorkplacePark	EncourageTele	EncourageTele	EncourageTele	EncourageTele	MarketCommu	MarketCommu	EmployeeVanp	EmployeeVanp	EmployeeVanp	ProvideRideSh	ProvideRideSh	ImplementSch	ImplementSchoolBusProgramPercentFamilyUsing
0			0			0		0			0				0		0		2	0		0	

Landscape Lawnmower Check	Landscape Lawnmower Percent Electric	Landscape Leafblower Check	Landscape Leafblower Percent Electric	Landscape Chainsaw Check	Landscape Chainsaw Percent Electric	Use Low VOC Paint Residential Interior Check	Use Low VOC Paint Residential Interior Value	Use Low VOC Paint Residential Exterior Check	Use Low VOC Paint Residential Exterior Value	Use Low VOC Paint Nonresidential Interior Check	Use Low VOC Paint Nonresidential Interior Value	Use Low VOC Paint Nonresidential Exterior Check	Use Low VOC Paint Nonresidential Exterior Value	Hearth Only Natural Gas Hearth Check	No Hearth Check	Use Low VOC Cleaning Supplies Check
0		0		0		0	50	0	100	0	250	0	250	0	0	0

Exceed Title 24 Check	Exceed Title 24 Check Percent Improvement	Install High Efficiency Lighting Check	Install High Efficiency Lighting Percent Energy Reduction	OnSite Renewable Energy Check	Kwh Generated Check	Kwh Generated	Percent Of Electricity Use Generated Check	Percent Of Electricity Use Generated

ApplianceType	ApplianceLandUseSubType	PercentImprovement
ClothWasher		30
DishWasher		15
Fan		50
Refrigerator		15

Apply Water Conservation Strategy Check	Apply Water Conservation Strategy Percent Reduction Indoor	Apply Water Conservation Strategy Percent Reduction Outdoor	Use Reclaimed Water Check	Percent Outdoor Reclaimed Water Use	Percent Indoor Reclaimed Water Use	Use Grey Water Check	Percent Outdoor Grey Water Use	Percent Indoor Grey Water Use	Install Low Flow Bathroom Faucet Check	Percent Reduction InFlow Bathroom Faucet	Install LowFlow Kitchen Faucet Check
0			0			0			0	32	0

Percent Reduction InFlow Kitchen Faucet	Install LowFlow Toilet Check	Percent Reduction InFlow Toilet	Install LowFlow Shower Check	Percent Reduction InFlow Shower	Turf Reduction Check	Turf Reduction Turf Area	Turf Reduction Percent Reduction	Use Water Efficient Irrigation System Check	Use Water Efficient Irrigation System Percent Reduction	Water Efficient Landscape Check	MAWA	ETWU
18	0	20	0	20	0			0	6.1	0		

InstituteRecyclingAndCompostingServicesCheck InstituteRecyclingAndCompostingServicesWastePercentReduction

OperOffRoadEquipmentType	OperOffRoadEquipmentNumber	OperHoursPerDay	OperDaysPerYear	OperHorsePower	OperLoadFactor	OperFuelType

SubModuleID	PhaseName	Season	Remarks
1			
3			
4			Average of construction estimates
5	Architectural Coating		
5	Building Construction		Engineering estimate
5	Demolition		Engineering estimate
5	Grading		Engineering estimate
5	Paving		Engineering estimate
5	Site Preparation		Engineering estimate
6			
8			
9			Engineering estimate
10			
25			

RECLAIM

South Coast AQMD Air District, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	43.56	1000sqft	1.00	43,560.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	31
Climate Zone	8			**Operational Year**	2015
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use -

Construction Phase - Average of construction estimates

Off-road Equipment -

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Trips and VMT -

Demolition -

Grading - Engineering estimate

Architectural Coating -

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstructionPhase	NumDays	100.00	250.00
tblConstructionPhase	NumDays	1.00	2.00
tblConstructionPhase	PhaseEndDate	1/2/2017	1/3/2017
tblConstructionPhase	PhaseEndDate	1/10/2017	6/14/2016
tblConstructionPhase	PhaseStartDate	1/19/2016	1/20/2016
tblConstructionPhase	PhaseStartDate	1/4/2017	6/8/2016
tblGrading	AcresOfGrading	0.00	1.00
tblOffRoadEquipment	HorsePower	8.00	125.00
tblOffRoadEquipment	LoadFactor	0.43	0.42
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Trenchers
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Paving
tblOffRoadEquipment	PhaseName		Demolition
tblOffRoadEquipment	PhaseName		Site Preparation
tblOffRoadEquipment	PhaseName		Building Construction
tblProjectCharacteristics	OperationalYear	2014	2015
tblTripsAndVMT	WorkerTripNumber	8.00	15.00
tblTripsAndVMT	WorkerTripNumber	5.00	8.00
tblTripsAndVMT	WorkerTripNumber	10.00	13.00

2.0 Emissions Summary

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2016	0.3813	2.7264	2.0892	3.2800e-003	0.0427	0.1684	0.2111	0.0122	0.1613	0.1735	0.0000	283.1063	283.1063	0.0559	0.0000	284.2792
2017	2.6200e-003	0.0188	0.0152	2.0000e-005	2.4000e-004	1.1400e-003	1.3800e-003	6.0000e-005	1.0900e-003	1.1500e-003	0.0000	2.1233	2.1233	4.0000e-004	0.0000	2.1317
Total	**0.3840**	**2.7453**	**2.1045**	**3.3000e-003**	**0.0429**	**0.1695**	**0.2125**	**0.0123**	**0.1623**	**0.1746**	**0.0000**	**285.2296**	**285.2296**	**0.0563**	**0.0000**	**286.4110**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2016	0.3813	2.6078	2.0892	3.2800e-003	0.0359	0.1684	0.2043	9.9500e-003	0.1613	0.1712	0.0000	283.1060	283.1060	0.0559	0.0000	284.2790
2017	2.6200e-003	0.0180	0.0152	2.0000e-005	2.4000e-004	1.1400e-003	1.3800e-003	6.0000e-005	1.0900e-003	1.1500e-003	0.0000	2.1233	2.1233	4.0000e-004	0.0000	2.1317
Total	**0.3840**	**2.6258**	**2.1045**	**3.3000e-003**	**0.0361**	**0.1695**	**0.2057**	**0.0100**	**0.1623**	**0.1724**	**0.0000**	**285.2293**	**285.2293**	**0.0563**	**0.0000**	**286.4107**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**4.35**	**0.00**	**0.00**	**15.87**	**0.00**	**3.20**	**18.62**	**0.00**	**1.31**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Energy	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	274.4767	274.4767	6.2600e-003	2.0200e-003	275.2336
Mobile	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848
Waste						0.0000	0.0000		0.0000	0.0000	10.9635	0.0000	10.9635	0.6479	0.0000	24.5700
Water						0.0000	0.0000		0.0000	0.0000	3.1958	73.0532	76.2490	0.3300	8.1100e-003	85.6915
Total	**0.2670**	**0.2411**	**0.7527**	**1.8700e-003**	**0.1096**	**6.2700e-003**	**0.1159**	**0.0293**	**6.0500e-003**	**0.0354**	**14.1593**	**477.6990**	**491.8584**	**0.9897**	**0.0101**	**515.7810**

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Energy	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	274.4767	274.4767	6.2600e-003	2.0200e-003	275.2336
Mobile	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848
Waste						0.0000	0.0000		0.0000	0.0000	10.9635	0.0000	10.9635	0.6479	0.0000	24.5700
Water						0.0000	0.0000		0.0000	0.0000	3.1958	73.0532	76.2490	0.3299	8.0900e-003	85.6864
Total	**0.2670**	**0.2411**	**0.7527**	**1.8700e-003**	**0.1096**	**6.2700e-003**	**0.1159**	**0.0293**	**6.0500e-003**	**0.0354**	**14.1593**	**477.6990**	**491.8584**	**0.9897**	**0.0101**	**515.7759**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.01**	**0.20**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10	
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2	
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250	
4	Paving	Paving	6/8/2016	6/14/2016	5	5	

Acres of Grading (Site Preparation Phase): 1

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0 (Architectural Coating – sqft)

<u>OffRoad Equipment</u>

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73
Demolition	Rubber Tired Dozers	1	8.00	255	0.40
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Building Construction	Cranes	1	6.00	226	0.29
Building Construction	Forklifts	1	6.00	89	0.20
Building Construction	Generator Sets	1	8.00	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37
Building Construction	Welders	2	8.00	46	0.45
Paving	Cement and Mortar Mixers	1	6.00	9	0.56
Paving	Paving Equipment	1	8.00	130	0.36
Paving	Plate Compactors	1	6.00	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Demolition	Cranes	1	8.00	226	0.29
Site Preparation	Trenchers	1	8.00	80	0.50
Building Construction	Aerial Lifts	1	8.00	62	0.31

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition	3	15.00	0.00	49.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Site Preparation	2	8.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Building Construction	6	18.00	7.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Paving	4	13.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

3.2 Demolition - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					5.3500e-003	0.0000	5.3500e-003	8.1000e-004	0.0000	8.1000e-004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0147	0.1511	0.0982	1.2000e-004		8.1400e-003	8.1400e-003		7.6300e-003	7.6300e-003	0.0000	10.9868	10.9868	2.7600e-003	0.0000	11.0448
Total	**0.0147**	**0.1511**	**0.0982**	**1.2000e-004**	**5.3500e-003**	**8.1400e-003**	**0.0135**	**8.1000e-004**	**7.6300e-003**	**8.4400e-003**	**0.0000**	**10.9868**	**10.9868**	**2.7600e-003**	**0.0000**	**11.0448**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	4.4000e-004	7.0800e-003	5.3500e-003	2.0000e-005	4.2000e-004	1.1000e-004	5.3000e-004	1.2000e-004	1.0000e-004	2.1000e-004	0.0000	1.6501	1.6501	1.0000e-005	0.0000	1.6503
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-004	4.4000e-004	4.6000e-003	1.0000e-005	8.2000e-004	1.0000e-005	8.3000e-004	2.2000e-004	1.0000e-005	2.2000e-004	0.0000	0.7709	0.7709	4.0000e-005	0.0000	0.7718
Total	**7.4000e-004**	**7.5200e-003**	**9.9500e-003**	**3.0000e-005**	**1.2400e-003**	**1.2000e-004**	**1.3600e-003**	**3.4000e-004**	**1.1000e-004**	**4.3000e-004**	**0.0000**	**2.4210**	**2.4210**	**5.0000e-005**	**0.0000**	**2.4221**

3.2 Demolition - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					2.0900e-003	0.0000	2.0900e-003	3.2000e-004	0.0000	3.2000e-004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0147	0.1511	0.0982	1.2000e-004		8.1400e-003	8.1400e-003		7.6300e-003	7.6300e-003	0.0000	10.9868	10.9868	2.7600e-003	0.0000	11.0448
Total	**0.0147**	**0.1511**	**0.0982**	**1.2000e-004**	**2.0900e-003**	**8.1400e-003**	**0.0102**	**3.2000e-004**	**7.6300e-003**	**7.9500e-003**	**0.0000**	**10.9868**	**10.9868**	**2.7600e-003**	**0.0000**	**11.0448**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	4.4000e-004	7.0800e-003	5.3500e-003	2.0000e-005	4.2000e-004	1.1000e-004	5.3000e-004	1.2000e-004	1.0000e-004	2.1000e-004	0.0000	1.6501	1.6501	1.0000e-005	0.0000	1.6503
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-004	4.4000e-004	4.6000e-003	1.0000e-005	8.2000e-004	1.0000e-005	8.3000e-004	2.2000e-004	1.0000e-005	2.2000e-004	0.0000	0.7709	0.7709	4.0000e-005	0.0000	0.7718
Total	**7.4000e-004**	**7.5200e-003**	**9.9500e-003**	**3.0000e-005**	**1.2400e-003**	**1.2000e-004**	**1.3600e-003**	**3.4000e-004**	**1.1000e-004**	**4.3000e-004**	**0.0000**	**2.4210**	**2.4210**	**5.0000e-005**	**0.0000**	**2.4221**

3.3 Site Preparation - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					5.8000e-003	0.0000	5.8000e-003	2.9500e-003	0.0000	2.9500e-003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	1.9800e-003	0.0203	0.0144	1.0000e-005		1.2000e-003	1.2000e-003		1.1000e-003	1.1000e-003	0.0000	1.3530	1.3530	4.1000e-004	0.0000	1.3616
Total	**1.9800e-003**	**0.0203**	**0.0144**	**1.0000e-005**	**5.8000e-003**	**1.2000e-003**	**7.0000e-003**	**2.9500e-003**	**1.1000e-003**	**4.0500e-003**	**0.0000**	**1.3530**	**1.3530**	**4.1000e-004**	**0.0000**	**1.3616**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-005	5.0000e-005	4.9000e-004	0.0000	9.0000e-005	0.0000	9.0000e-005	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0822	0.0822	0.0000	0.0000	0.0823
Total	**3.0000e-005**	**5.0000e-005**	**4.9000e-004**	**0.0000**	**9.0000e-005**	**0.0000**	**9.0000e-005**	**2.0000e-005**	**0.0000**	**2.0000e-005**	**0.0000**	**0.0822**	**0.0822**	**0.0000**	**0.0000**	**0.0823**

3.3 Site Preparation - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					2.2600e-003	0.0000	2.2600e-003	1.1500e-003	0.0000	1.1500e-003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	1.9800e-003	0.0154	0.0144	1.0000e-005		1.2000e-003	1.2000e-003		1.1000e-003	1.1000e-003	0.0000	1.3530	1.3530	4.1000e-004	0.0000	1.3616
Total	**1.9800e-003**	**0.0154**	**0.0144**	**1.0000e-005**	**2.2600e-003**	**1.2000e-003**	**3.4600e-003**	**1.1500e-003**	**1.1000e-003**	**2.2500e-003**	**0.0000**	**1.3530**	**1.3530**	**4.1000e-004**	**0.0000**	**1.3616**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-005	5.0000e-005	4.9000e-004	0.0000	9.0000e-005	0.0000	9.0000e-005	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0822	0.0822	0.0000	0.0000	0.0823
Total	**3.0000e-005**	**5.0000e-005**	**4.9000e-004**	**0.0000**	**9.0000e-005**	**0.0000**	**9.0000e-005**	**2.0000e-005**	**0.0000**	**2.0000e-005**	**0.0000**	**0.0822**	**0.0822**	**0.0000**	**0.0000**	**0.0823**

3.4 Building Construction - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.3454	2.4380	1.7133	2.6100e-003		0.1564	0.1564		0.1501	0.1501	0.0000	226.1142	226.1142	0.0507	0.0000	227.1795
Total	**0.3454**	**2.4380**	**1.7133**	**2.6100e-003**		**0.1564**	**0.1564**		**0.1501**	**0.1501**	**0.0000**	**226.1142**	**226.1142**	**0.0507**	**0.0000**	**227.1795**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	7.7000e-003	0.0784	0.1010	1.9000e-004	5.3400e-003	1.2400e-003	6.5800e-003	1.5200e-003	1.1400e-003	2.6600e-003	0.0000	17.1079	17.1079	1.2000e-004	0.0000	17.1105
Worker	8.9700e-003	0.0132	0.1370	3.0000e-004	0.0245	2.1000e-004	0.0247	6.5000e-003	1.9000e-004	6.7000e-003	0.0000	22.9422	22.9422	1.2400e-003	0.0000	22.9681
Total	**0.0167**	**0.0916**	**0.2380**	**4.9000e-004**	**0.0298**	**1.4500e-003**	**0.0313**	**8.0200e-003**	**1.3300e-003**	**9.3600e-003**	**0.0000**	**40.0501**	**40.0501**	**1.3600e-003**	**0.0000**	**40.0786**

3.4 Building Construction - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.3454	2.3242	1.7133	2.6100e-003		0.1564	0.1564		0.1501	0.1501	0.0000	226.1139	226.1139	0.0507	0.0000	227.1793
Total	**0.3454**	**2.3242**	**1.7133**	**2.6100e-003**		**0.1564**	**0.1564**		**0.1501**	**0.1501**	**0.0000**	**226.1139**	**226.1139**	**0.0507**	**0.0000**	**227.1793**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	7.7000e-003	0.0784	0.1010	1.9000e-004	5.3400e-003	1.2400e-003	6.5800e-003	1.5200e-003	1.1400e-003	2.6600e-003	0.0000	17.1079	17.1079	1.2000e-004	0.0000	17.1105
Worker	8.9700e-003	0.0132	0.1370	3.0000e-004	0.0245	2.1000e-004	0.0247	6.5000e-003	1.9000e-004	6.7000e-003	0.0000	22.9422	22.9422	1.2400e-003	0.0000	22.9681
Total	**0.0167**	**0.0916**	**0.2380**	**4.9000e-004**	**0.0298**	**1.4500e-003**	**0.0313**	**8.0200e-003**	**1.3300e-003**	**9.3600e-003**	**0.0000**	**40.0501**	**40.0501**	**1.3600e-003**	**0.0000**	**40.0786**

3.4 Building Construction - 2017

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	2.5000e-003	0.0182	0.0135	2.0000e-005		1.1300e-003	1.1300e-003		1.0800e-003	1.0800e-003	0.0000	1.8096	1.8096	3.9000e-004	0.0000	1.8179
Total	**2.5000e-003**	**0.0182**	**0.0135**	**2.0000e-005**		**1.1300e-003**	**1.1300e-003**		**1.0800e-003**	**1.0800e-003**	**0.0000**	**1.8096**	**1.8096**	**3.9000e-004**	**0.0000**	**1.8179**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	6.0000e-005	5.7000e-004	7.7000e-004	0.0000	4.0000e-005	1.0000e-005	5.0000e-005	1.0000e-005	1.0000e-005	2.0000e-005	0.0000	0.1357	0.1357	0.0000	0.0000	0.1358
Worker	6.0000e-005	1.0000e-004	1.0000e-003	0.0000	2.0000e-004	0.0000	2.0000e-004	5.0000e-005	0.0000	5.0000e-005	0.0000	0.1779	0.1779	1.0000e-005	0.0000	0.1781
Total	**1.2000e-004**	**6.7000e-004**	**1.7700e-003**	**0.0000**	**2.4000e-004**	**1.0000e-005**	**2.5000e-004**	**6.0000e-005**	**1.0000e-005**	**7.0000e-005**	**0.0000**	**0.3136**	**0.3136**	**1.0000e-005**	**0.0000**	**0.3139**

3.4 Building Construction - 2017

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	2.5000e-003	0.0174	0.0135	2.0000e-005		1.1300e-003	1.1300e-003		1.0800e-003	1.0800e-003	0.0000	1.8096	1.8096	3.9000e-004	0.0000	1.8179
Total	**2.5000e-003**	**0.0174**	**0.0135**	**2.0000e-005**		**1.1300e-003**	**1.1300e-003**		**1.0800e-003**	**1.0800e-003**	**0.0000**	**1.8096**	**1.8096**	**3.9000e-004**	**0.0000**	**1.8179**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	6.0000e-005	5.7000e-004	7.7000e-004	0.0000	4.0000e-005	1.0000e-005	5.0000e-005	1.0000e-005	1.0000e-005	2.0000e-005	0.0000	0.1357	0.1357	0.0000	0.0000	0.1358
Worker	6.0000e-005	1.0000e-004	1.0000e-003	0.0000	2.0000e-004	0.0000	2.0000e-004	5.0000e-005	0.0000	5.0000e-005	0.0000	0.1779	0.1779	1.0000e-005	0.0000	0.1781
Total	**1.2000e-004**	**6.7000e-004**	**1.7700e-003**	**0.0000**	**2.4000e-004**	**1.0000e-005**	**2.5000e-004**	**6.0000e-005**	**1.0000e-005**	**7.0000e-005**	**0.0000**	**0.3136**	**0.3136**	**1.0000e-005**	**0.0000**	**0.3139**

3.5 Paving - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.7300e-003	0.0178	0.0130	2.0000e-005		1.1000e-003	1.1000e-003		1.0100e-003	1.0100e-003	0.0000	1.7650	1.7650	5.2000e-004	0.0000	1.7759
Paving	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**1.7300e-003**	**0.0178**	**0.0130**	**2.0000e-005**		**1.1000e-003**	**1.1000e-003**		**1.0100e-003**	**1.0100e-003**	**0.0000**	**1.7650**	**1.7650**	**5.2000e-004**	**0.0000**	**1.7759**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	1.3000e-004	1.9000e-004	1.9900e-003	0.0000	3.6000e-004	0.0000	3.6000e-004	9.0000e-005	0.0000	1.0000e-004	0.0000	0.3341	0.3341	2.0000e-005	0.0000	0.3344
Total	**1.3000e-004**	**1.9000e-004**	**1.9900e-003**	**0.0000**	**3.6000e-004**	**0.0000**	**3.6000e-004**	**9.0000e-005**	**0.0000**	**1.0000e-004**	**0.0000**	**0.3341**	**0.3341**	**2.0000e-005**	**0.0000**	**0.3344**

3.5 Paving - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.7300e-003	0.0178	0.0130	2.0000e-005		1.1000e-003	1.1000e-003		1.0100e-003	1.0100e-003	0.0000	1.7650	1.7650	5.2000e-004	0.0000	1.7759
Paving	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**1.7300e-003**	**0.0178**	**0.0130**	**2.0000e-005**		**1.1000e-003**	**1.1000e-003**		**1.0100e-003**	**1.0100e-003**	**0.0000**	**1.7650**	**1.7650**	**5.2000e-004**	**0.0000**	**1.7759**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	1.3000e-004	1.9000e-004	1.9900e-003	0.0000	3.6000e-004	0.0000	3.6000e-004	9.0000e-005	0.0000	1.0000e-004	0.0000	0.3341	0.3341	2.0000e-005	0.0000	0.3344
Total	**1.3000e-004**	**1.9000e-004**	**1.9900e-003**	**0.0000**	**3.6000e-004**	**0.0000**	**3.6000e-004**	**9.0000e-005**	**0.0000**	**1.0000e-004**	**0.0000**	**0.3341**	**0.3341**	**2.0000e-005**	**0.0000**	**0.3344**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848
Unmitigated	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	65.34	65.34	65.34	289,344	289,344
Total	65.34	65.34	65.34	289,344	289,344

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.514499	0.060499	0.179997	0.139763	0.042095	0.006675	0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	224.1739	224.1739	5.2900e-003	1.1000e-003	224.6247
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	224.1739	224.1739	5.2900e-003	1.1000e-003	224.6247
NaturalGas Mitigated	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089
NaturalGas Unmitigated	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
General Heavy Industry	942638	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089
Total		**5.0800e-003**	**0.0462**	**0.0388**	**2.8000e-004**		**3.5100e-003**	**3.5100e-003**		**3.5100e-003**	**3.5100e-003**	**0.0000**	**50.3028**	**50.3028**	**9.6000e-004**	**9.2000e-004**	**50.6089**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
General Heavy Industry	942638	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089
Total		**5.0800e-003**	**0.0462**	**0.0388**	**2.8000e-004**		**3.5100e-003**	**3.5100e-003**		**3.5100e-003**	**3.5100e-003**	**0.0000**	**50.3028**	**50.3028**	**9.6000e-004**	**9.2000e-004**	**50.6089**

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
General Heavy Industry	402494	224.1739	5.2900e-003	1.1000e-003	224.6247
Total		**224.1739**	**5.2900e-003**	**1.1000e-003**	**224.6247**

5.3 Energy by Land Use - Electricity

Mitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
General Heavy Industry	402494	224.1739	5.2900e-003	1.1000e-003	224.6247
Total		**224.1739**	**5.2900e-003**	**1.1000e-003**	**224.6247**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Unmitigated	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0505					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.1574					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	6.0000e-005	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Total	**0.2079**	**1.0000e-005**	**5.8000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**1.0800e-003**	**1.0800e-003**	**0.0000**	**0.0000**	**1.1500e-003**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0505					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.1574					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	6.0000e-005	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Total	**0.2079**	**1.0000e-005**	**5.8000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**1.0800e-003**	**1.0800e-003**	**0.0000**	**0.0000**	**1.1500e-003**

7.0 Water Detail

7.1 Mitigation Measures Water

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	76.2490	0.3299	8.0900e-003	85.6864
Unmitigated	76.2490	0.3300	8.1100e-003	85.6915

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
General Heavy Industry	10.0733 / 0	76.2490	0.3300	8.1100e-003	85.6915
Total		**76.2490**	**0.3300**	**8.1100e-003**	**85.6915**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
General Heavy Industry	10.0733 / 0	76.2490	0.3299	8.0900e-003	85.6864
Total		**76.2490**	**0.3299**	**8.0900e-003**	**85.6864**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	10.9635	0.6479	0.0000	24.5700
Unmitigated	10.9635	0.6479	0.0000	24.5700

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
General Heavy Industry	54.01	10.9635	0.6479	0.0000	24.5700
Total		**10.9635**	**0.6479**	**0.0000**	**24.5700**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
General Heavy Industry	54.01	10.9635	0.6479	0.0000	24.5700
Total		**10.9635**	**0.6479**	**0.0000**	**24.5700**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Vegetation

RECLAIM

South Coast AQMD Air District, Summer

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	43.56	1000sqft	1.00	43,560.00	0

1.2 Other Project Characteristics

Urbanization Urban **Wind Speed (m/s)** 2.2 **Precipitation Freq (Days)** 31

Climate Zone 8 **Operational Year** 2015

Utility Company Los Angeles Department of Water & Power

CO2 Intensity (lb/MWhr) 1227.89 **CH4 Intensity (lb/MWhr)** 0.029 **N2O Intensity (lb/MWhr)** 0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use -

Construction Phase - Average of construction estimates

Off-road Equipment -

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Trips and VMT -

Demolition -

Grading - Engineering estimate

Architectural Coating -

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstructionPhase	NumDays	100.00	250.00
tblConstructionPhase	NumDays	1.00	2.00
tblConstructionPhase	PhaseEndDate	1/2/2017	1/3/2017
tblConstructionPhase	PhaseEndDate	1/10/2017	6/14/2016
tblConstructionPhase	PhaseStartDate	1/19/2016	1/20/2016
tblConstructionPhase	PhaseStartDate	1/4/2017	6/8/2016
tblGrading	AcresOfGrading	0.00	1.00
tblOffRoadEquipment	HorsePower	8.00	125.00
tblOffRoadEquipment	LoadFactor	0.43	0.42
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Trenchers
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Paving
tblOffRoadEquipment	PhaseName		Demolition
tblOffRoadEquipment	PhaseName		Site Preparation
tblOffRoadEquipment	PhaseName		Building Construction
tblProjectCharacteristics	OperationalYear	2014	2015
tblTripsAndVMT	WorkerTripNumber	8.00	15.00
tblTripsAndVMT	WorkerTripNumber	5.00	8.00
tblTripsAndVMT	WorkerTripNumber	10.00	13.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6645	31.6449	21.7158	0.0346	5.8890	1.7129	7.0870	2.9774	1.6266	4.0796	0.0000	3,309.666 9	3,309.666 9	0.6983	0.0000	3,324.330 0
2017	2.6227	18.7997	15.1854	0.0251	0.2450	1.1365	1.3815	0.0658	1.0901	1.1559	0.0000	2,350.813 3	2,350.813 3	0.4446	0.0000	2,360.149 5
Total	**6.2872**	**50.4446**	**36.9013**	**0.0597**	**6.1340**	**2.8494**	**8.4685**	**3.0432**	**2.7167**	**5.2355**	**0.0000**	**5,660.480 2**	**5,660.480 2**	**1.1428**	**0.0000**	**5,684.479 6**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6645	31.6449	21.7158	0.0346	2.3513	1.7129	3.5493	1.1757	1.6266	2.2778	0.0000	3,309.666 9	3,309.666 9	0.6983	0.0000	3,324.330 0
2017	2.6227	18.0031	15.1854	0.0251	0.2450	1.1365	1.3815	0.0658	1.0901	1.1559	0.0000	2,350.813 3	2,350.813 3	0.4446	0.0000	2,360.149 5
Total	**6.2872**	**49.6480**	**36.9013**	**0.0597**	**2.5962**	**2.8494**	**4.9307**	**1.2415**	**2.7167**	**3.4337**	**0.0000**	**5,660.480 2**	**5,660.480 2**	**1.1428**	**0.0000**	**5,684.479 6**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**1.58**	**0.00**	**0.00**	**57.67**	**0.00**	**41.78**	**59.21**	**0.00**	**34.41**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028
Total	**1.4690**	**1.2488**	**4.2297**	**0.0106**	**0.6134**	**0.0344**	**0.6478**	**0.1639**	**0.0332**	**0.1971**		**1,123.6367**	**1,123.6367**	**0.0395**	**5.5700e-003**	**1,126.1938**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028
Total	**1.4690**	**1.2488**	**4.2297**	**0.0106**	**0.6134**	**0.0344**	**0.6478**	**0.1639**	**0.0332**	**0.1971**		**1,123.6367**	**1,123.6367**	**0.0395**	**5.5700e-003**	**1,126.1938**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10	
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2	
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250	
4	Paving	Paving	6/8/2016	6/14/2016	5	5	

Acres of Grading (Site Preparation Phase): 1

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73
Demolition	Rubber Tired Dozers	1	8.00	255	0.40
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Building Construction	Cranes	1	6.00	226	0.29
Building Construction	Forklifts	1	6.00	89	0.20
Building Construction	Generator Sets	1	8.00	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37
Building Construction	Welders	2	8.00	46	0.45
Paving	Cement and Mortar Mixers	1	6.00	9	0.56
Paving	Paving Equipment	1	8.00	130	0.36
Paving	Plate Compactors	1	6.00	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Demolition	Cranes	1	8.00	226	0.29
Site Preparation	Trenchers	1	8.00	80	0.50
Building Construction	Aerial Lifts	1	8.00	62	0.31

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition	3	15.00	0.00	49.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Site Preparation	2	8.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Building Construction	6	18.00	7.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Paving	4	13.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

3.2 Demolition - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.0700	0.0000	1.0700	0.1620	0.0000	0.1620			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254		2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**1.0700**	**1.6279**	**2.6978**	**0.1620**	**1.5254**	**1.6874**		**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0838	1.3432	0.9500	3.6100e-003	0.0854	0.0213	0.1067	0.0234	0.0196	0.0430		364.1444	364.1444	2.5900e-003		364.1987
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0627	0.0783	0.9750	2.1200e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		178.4188	178.4188	9.1500e-003		178.6110
Total	**0.1465**	**1.4215**	**1.9251**	**5.7300e-003**	**0.2530**	**0.0227**	**0.2758**	**0.0679**	**0.0209**	**0.0887**		**542.5631**	**542.5631**	**0.0117**		**542.8097**

3.2 Demolition - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					0.4173	0.0000	0.4173	0.0632	0.0000	0.0632			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254	0.0000	2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**0.4173**	**1.6279**	**2.0452**	**0.0632**	**1.5254**	**1.5886**	**0.0000**	**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0838	1.3432	0.9500	3.6100e-003	0.0854	0.0213	0.1067	0.0234	0.0196	0.0430		364.1444	364.1444	2.5900e-003		364.1987
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0627	0.0783	0.9750	2.1200e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		178.4188	178.4188	9.1500e-003		178.6110
Total	**0.1465**	**1.4215**	**1.9251**	**5.7300e-003**	**0.2530**	**0.0227**	**0.2758**	**0.0679**	**0.0209**	**0.0887**		**542.5631**	**542.5631**	**0.0117**		**542.8097**

3.3 Site Preparation - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					5.7996	0.0000	5.7996	2.9537	0.0000	2.9537			0.0000			0.0000
Off-Road	1.9799	20.2613	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015		1,491.4061	1,491.4061	0.4499		1,500.8532
Total	**1.9799**	**20.2613**	**14.4005**	**0.0143**	**5.7996**	**1.1973**	**6.9968**	**2.9537**	**1.1015**	**4.0552**		**1,491.4061**	**1,491.4061**	**0.4499**		**1,500.8532**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0334	0.0418	0.5200	1.1300e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		95.1567	95.1567	4.8800e-003		95.2592
Total	**0.0334**	**0.0418**	**0.5200**	**1.1300e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**95.1567**	**95.1567**	**4.8800e-003**		**95.2592**

3.3 Site Preparation - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					2.2618	0.0000	2.2618	1.1519	0.0000	1.1519			0.0000			0.0000
Off-Road	1.9799	15.3919	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015	0.0000	1,491.4061	1,491.4061	0.4499		1,500.8532
Total	**1.9799**	**15.3919**	**14.4005**	**0.0143**	**2.2618**	**1.1973**	**3.4591**	**1.1519**	**1.1015**	**2.2534**	**0.0000**	**1,491.4061**	**1,491.4061**	**0.4499**		**1,500.8532**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0334	0.0418	0.5200	1.1300e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		95.1567	95.1567	4.8800e-003		95.2592
Total	**0.0334**	**0.0418**	**0.5200**	**1.1300e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**95.1567**	**95.1567**	**4.8800e-003**		**95.2592**

3.4 Building Construction - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	19.6612	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102		2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**19.6612**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**		**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0583	0.6046	0.6971	1.5200e-003	0.0438	9.9500e-003	0.0537	0.0125	9.1500e-003	0.0216		152.6202	152.6202	1.0900e-003		152.6431
Worker	0.0752	0.0940	1.1700	2.5500e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		214.1025	214.1025	0.0110		214.3332
Total	**0.1335**	**0.6986**	**1.8672**	**4.0700e-003**	**0.2450**	**0.0116**	**0.2566**	**0.0658**	**0.0107**	**0.0765**		**366.7228**	**366.7228**	**0.0121**		**366.9763**

3.4 Building Construction - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	18.7438	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102	0.0000	2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**18.7438**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**	**0.0000**	**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0583	0.6046	0.6971	1.5200e-003	0.0438	9.9500e-003	0.0537	0.0125	9.1500e-003	0.0216		152.6202	152.6202	1.0900e-003		152.6431
Worker	0.0752	0.0940	1.1700	2.5500e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		214.1025	214.1025	0.0110		214.3332
Total	**0.1335**	**0.6986**	**1.8672**	**4.0700e-003**	**0.2450**	**0.0116**	**0.2566**	**0.0658**	**0.0107**	**0.0765**		**366.7228**	**366.7228**	**0.0121**		**366.9763**

3.4 Building Construction - 2017

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	18.1647	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804		1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**18.1647**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**		**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0534	0.5501	0.6556	1.5200e-003	0.0438	8.8800e-003	0.0526	0.0125	8.1700e-003	0.0206		150.1482	150.1482	1.0500e-003		150.1703
Worker	0.0676	0.0849	1.0583	2.5500e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		205.9080	205.9080	0.0101		206.1209
Total	**0.1210**	**0.6350**	**1.7139**	**4.0700e-003**	**0.2450**	**0.0105**	**0.2555**	**0.0658**	**9.6600e-003**	**0.0755**		**356.0563**	**356.0563**	**0.0112**		**356.2912**

3.4 Building Construction - 2017

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	17.3681	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804	0.0000	1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**17.3681**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**	**0.0000**	**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0534	0.5501	0.6556	1.5200e-003	0.0438	8.8800e-003	0.0526	0.0125	8.1700e-003	0.0206		150.1482	150.1482	1.0500e-003		150.1703
Worker	0.0676	0.0849	1.0583	2.5500e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		205.9080	205.9080	0.0101		206.1209
Total	**0.1210**	**0.6350**	**1.7139**	**4.0700e-003**	**0.2450**	**0.0105**	**0.2555**	**0.0658**	**9.6600e-003**	**0.0755**		**356.0563**	**356.0563**	**0.0112**		**356.2912**

3.5 Paving - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046		778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**		**778.2485**	**778.2485**	**0.2273**		**783.0208**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0543	0.0679	0.8450	1.8400e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		154.6296	154.6296	7.9300e-003		154.7962
Total	**0.0543**	**0.0679**	**0.8450**	**1.8400e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**154.6296**	**154.6296**	**7.9300e-003**		**154.7962**

3.5 Paving - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046	0.0000	778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**	**0.0000**	**778.2485**	**778.2485**	**0.2273**		**783.0208**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0543	0.0679	0.8450	1.8400e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		154.6296	154.6296	7.9300e-003		154.7962
Total	**0.0543**	**0.0679**	**0.8450**	**1.8400e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**154.6296**	**154.6296**	**7.9300e-003**		**154.7962**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028
Unmitigated	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	65.34	65.34	65.34	289,344	289,344
Total	65.34	65.34	65.34	289,344	289,344

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.514499	0.060499	0.179997	0.139763	0.042095	0.006675	0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098

4.4 Fleet Mix

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
NaturalGas Unmitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2582.57	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2.58257	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Unmitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Vegetation

RECLAIM

South Coast AQMD Air District, Winter

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	43.56	1000sqft	1.00	43,560.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	31
Climate Zone	8			**Operational Year**	2015
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use -

Construction Phase - Average of construction estimates

Off-road Equipment -

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Trips and VMT -

Demolition -

Grading - Engineering estimate

Architectural Coating -

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstructionPhase	NumDays	100.00	250.00
tblConstructionPhase	NumDays	1.00	2.00
tblConstructionPhase	PhaseEndDate	1/2/2017	1/3/2017
tblConstructionPhase	PhaseEndDate	1/10/2017	6/14/2016
tblConstructionPhase	PhaseStartDate	1/19/2016	1/20/2016
tblConstructionPhase	PhaseStartDate	1/4/2017	6/8/2016
tblGrading	AcresOfGrading	0.00	1.00
tblOffRoadEquipment	HorsePower	8.00	125.00
tblOffRoadEquipment	LoadFactor	0.43	0.42
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Trenchers
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Paving
tblOffRoadEquipment	PhaseName		Demolition
tblOffRoadEquipment	PhaseName		Site Preparation
tblOffRoadEquipment	PhaseName		Building Construction
tblProjectCharacteristics	OperationalYear	2014	2015
tblTripsAndVMT	WorkerTripNumber	8.00	15.00
tblTripsAndVMT	WorkerTripNumber	5.00	8.00
tblTripsAndVMT	WorkerTripNumber	10.00	13.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6728	31.7013	21.6972	0.0343	5.8890	1.7130	7.0870	2.9774	1.6267	4.0796	0.0000	3,285.526 6	3,285.526 6	0.6983	0.0000	3,300.190 4
2017	2.6289	18.8215	15.2376	0.0249	0.2450	1.1366	1.3815	0.0658	1.0901	1.1560	0.0000	2,336.757 9	2,336.757 9	0.4446	0.0000	2,346.094 8
Total	**6.3017**	**50.5228**	**36.9348**	**0.0593**	**6.1340**	**2.8496**	**8.4685**	**3.0432**	**2.7168**	**5.2355**	**0.0000**	**5,622.284 5**	**5,622.284 5**	**1.1429**	**0.0000**	**5,646.285 2**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6728	31.7013	21.6972	0.0343	2.3513	1.7130	3.5493	1.1757	1.6267	2.2778	0.0000	3,285.526 6	3,285.526 6	0.6983	0.0000	3,300.190 4
2017	2.6289	18.0249	15.2376	0.0249	0.2450	1.1366	1.3815	0.0658	1.0901	1.1560	0.0000	2,336.757 9	2,336.757 9	0.4446	0.0000	2,346.094 8
Total	**6.3017**	**49.7262**	**36.9348**	**0.0593**	**2.5962**	**2.8496**	**4.9308**	**1.2415**	**2.7168**	**3.4338**	**0.0000**	**5,622.284 5**	**5,622.284 5**	**1.1429**	**0.0000**	**5,646.285 2**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**1.58**	**0.00**	**0.00**	**57.67**	**0.00**	**41.78**	**59.21**	**0.00**	**34.41**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319
Total	**1.4776**	**1.3026**	**4.0817**	**0.0101**	**0.6134**	**0.0345**	**0.6479**	**0.1639**	**0.0333**	**0.1971**		**1,083.5655**	**1,083.5655**	**0.0396**	**5.5700e-003**	**1,086.1230**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319
Total	**1.4776**	**1.3026**	**4.0817**	**0.0101**	**0.6134**	**0.0345**	**0.6479**	**0.1639**	**0.0333**	**0.1971**		**1,083.5655**	**1,083.5655**	**0.0396**	**5.5700e-003**	**1,086.1230**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10	
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2	
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250	
4	Paving	Paving	6/8/2016	6/14/2016	5	5	

Acres of Grading (Site Preparation Phase): 1

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73
Demolition	Rubber Tired Dozers	1	8.00	255	0.40
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Building Construction	Cranes	1	6.00	226	0.29
Building Construction	Forklifts	1	6.00	89	0.20
Building Construction	Generator Sets	1	8.00	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37
Building Construction	Welders	2	8.00	46	0.45
Paving	Cement and Mortar Mixers	1	6.00	9	0.56
Paving	Paving Equipment	1	8.00	130	0.36
Paving	Plate Compactors	1	6.00	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Demolition	Cranes	1	8.00	226	0.29
Site Preparation	Trenchers	1	8.00	80	0.50
Building Construction	Aerial Lifts	1	8.00	62	0.31

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition	3	15.00	0.00	49.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Site Preparation	2	8.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Building Construction	6	18.00	7.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Paving	4	13.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

3.2 Demolition - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.0700	0.0000	1.0700	0.1620	0.0000	0.1620			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254		2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**1.0700**	**1.6279**	**2.6978**	**0.1620**	**1.5254**	**1.6874**		**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0886	1.3919	1.0891	3.6100e-003	0.0854	0.0214	0.1068	0.0234	0.0197	0.0430		363.2785	363.2785	2.6200e-003		363.3336
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0640	0.0860	0.8984	1.9900e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		167.3573	167.3573	9.1500e-003		167.5495
Total	**0.1525**	**1.4779**	**1.9875**	**5.6000e-003**	**0.2530**	**0.0228**	**0.2758**	**0.0679**	**0.0210**	**0.0888**		**530.6358**	**530.6358**	**0.0118**		**530.8831**

3.2 Demolition - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					0.4173	0.0000	0.4173	0.0632	0.0000	0.0632			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254	0.0000	2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**0.4173**	**1.6279**	**2.0452**	**0.0632**	**1.5254**	**1.5886**	**0.0000**	**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0886	1.3919	1.0891	3.6100e-003	0.0854	0.0214	0.1068	0.0234	0.0197	0.0430		363.2785	363.2785	2.6200e-003		363.3336
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0640	0.0860	0.8984	1.9900e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		167.3573	167.3573	9.1500e-003		167.5495
Total	**0.1525**	**1.4779**	**1.9875**	**5.6000e-003**	**0.2530**	**0.0228**	**0.2758**	**0.0679**	**0.0210**	**0.0888**		**530.6358**	**530.6358**	**0.0118**		**530.8831**

3.3 Site Preparation - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					5.7996	0.0000	5.7996	2.9537	0.0000	2.9537			0.0000			0.0000
Off-Road	1.9799	20.2613	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015		1,491.4061	1,491.4061	0.4499		1,500.8532
Total	**1.9799**	**20.2613**	**14.4005**	**0.0143**	**5.7996**	**1.1973**	**6.9968**	**2.9537**	**1.1015**	**4.0552**		**1,491.4061**	**1,491.4061**	**0.4499**		**1,500.8532**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0341	0.0459	0.4791	1.0600e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		89.2572	89.2572	4.8800e-003		89.3598
Total	**0.0341**	**0.0459**	**0.4791**	**1.0600e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**89.2572**	**89.2572**	**4.8800e-003**		**89.3598**

3.3 Site Preparation - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					2.2618	0.0000	2.2618	1.1519	0.0000	1.1519			0.0000			0.0000
Off-Road	1.9799	15.3919	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015	0.0000	1,491.406 1	1,491.406 1	0.4499		1,500.853 2
Total	**1.9799**	**15.3919**	**14.4005**	**0.0143**	**2.2618**	**1.1973**	**3.4591**	**1.1519**	**1.1015**	**2.2534**	**0.0000**	**1,491.406 1**	**1,491.406 1**	**0.4499**		**1,500.853 2**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0341	0.0459	0.4791	1.0600e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		89.2572	89.2572	4.8800e-003		89.3598
Total	**0.0341**	**0.0459**	**0.4791**	**1.0600e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**89.2572**	**89.2572**	**4.8800e-003**		**89.3598**

3.4 Building Construction - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	19.6612	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102		2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**19.6612**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**		**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0639	0.6198	0.8369	1.5100e-003	0.0438	0.0101	0.0538	0.0125	9.2500e-003	0.0217		151.3403	151.3403	1.1200e-003		151.3639
Worker	0.0768	0.1032	1.0780	2.3900e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		200.8288	200.8288	0.0110		201.0594
Total	**0.1407**	**0.7230**	**1.9150**	**3.9000e-003**	**0.2450**	**0.0117**	**0.2567**	**0.0658**	**0.0108**	**0.0766**		**352.1690**	**352.1690**	**0.0121**		**352.4233**

3.4 Building Construction - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	18.7438	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102	0.0000	2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**18.7438**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**	**0.0000**	**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0639	0.6198	0.8369	1.5100e-003	0.0438	0.0101	0.0538	0.0125	9.2500e-003	0.0217		151.3403	151.3403	1.1200e-003		151.3639
Worker	0.0768	0.1032	1.0780	2.3900e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		200.8288	200.8288	0.0110		201.0594
Total	**0.1407**	**0.7230**	**1.9150**	**3.9000e-003**	**0.2450**	**0.0117**	**0.2567**	**0.0658**	**0.0108**	**0.0766**		**352.1690**	**352.1690**	**0.0121**		**352.4233**

3.4 Building Construction - 2017

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	18.1647	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804		1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**18.1647**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**		**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0584	0.5637	0.7945	1.5100e-003	0.0438	8.9600e-003	0.0527	0.0125	8.2500e-003	0.0207		148.8859	148.8859	1.0900e-003		148.9087
Worker	0.0688	0.0931	0.9716	2.3900e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		193.1150	193.1150	0.0101		193.3278
Total	**0.1272**	**0.6568**	**1.7661**	**3.9000e-003**	**0.2450**	**0.0106**	**0.2556**	**0.0658**	**9.7400e-003**	**0.0756**		**342.0009**	**342.0009**	**0.0112**		**342.2365**

3.4 Building Construction - 2017

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	17.3681	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804	0.0000	1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**17.3681**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**	**0.0000**	**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0584	0.5637	0.7945	1.5100e-003	0.0438	8.9600e-003	0.0527	0.0125	8.2500e-003	0.0207		148.8859	148.8859	1.0900e-003		148.9087
Worker	0.0688	0.0931	0.9716	2.3900e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		193.1150	193.1150	0.0101		193.3278
Total	**0.1272**	**0.6568**	**1.7661**	**3.9000e-003**	**0.2450**	**0.0106**	**0.2556**	**0.0658**	**9.7400e-003**	**0.0756**		**342.0009**	**342.0009**	**0.0112**		**342.2365**

3.5 Paving - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046		778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**		**778.2485**	**778.2485**	**0.2273**		**783.0208**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0555	0.0745	0.7786	1.7300e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		145.0430	145.0430	7.9300e-003		145.2096
Total	**0.0555**	**0.0745**	**0.7786**	**1.7300e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**145.0430**	**145.0430**	**7.9300e-003**		**145.2096**

3.5 Paving - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046	0.0000	778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**	**0.0000**	**778.2485**	**778.2485**	**0.2273**		**783.0208**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0555	0.0745	0.7786	1.7300e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		145.0430	145.0430	7.9300e-003		145.2096
Total	**0.0555**	**0.0745**	**0.7786**	**1.7300e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**145.0430**	**145.0430**	**7.9300e-003**		**145.2096**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
Mitigated	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319
Unmitigated	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	65.34	65.34	65.34	289,344	289,344
Total	65.34	65.34	65.34	289,344	289,344

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.514499	0.060499	0.179997	0.139763	0.042095	0.006675	0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
NaturalGas Unmitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2582.57	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2.58257	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Unmitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Vegetation

APPENDIX F

NOTICE OF PREPARATION/INITIAL STUDY (NOP/IS) (ENVIRONMENTAL CHECKLIST)

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 • www.aqmd.gov

SUBJECT: **NOTICE OF PREPARATION OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT**

PROJECT TITLE: **PROPOSED AMENDED REGULATION XX - REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)**

In accordance with the California Environmental Quality Act (CEQA), the South Coast Air Quality Management District (SCAQMD), as the Lead Agency, has prepared this Notice of Preparation (NOP) and Initial Study (IS). This NOP serves two purposes: 1) to solicit information on the scope of the environmental analysis for the proposed project; and, 2) to notify the public that the SCAQMD will prepare a Draft Program Environmental Assessment (PEA) to further assess potential environmental impacts that may result from implementing the proposed project.

This letter, NOP and the attached IS are not SCAQMD applications or forms requiring a response from you. Their purpose is simply to provide information to you on the above project. If the proposed project has no bearing on you or your organization, no action on your part is necessary.

Comments focusing on your area of expertise, your agency's area of jurisdiction, if applicable, or issues relative to the environmental analysis should be addressed to Ms. Barbara Radlein (c/o CEQA) at the address shown above, or sent by fax to (909) 396-3324 or by email to bradlein@aqmd.gov . Comments must be received no later than 5:00 p.m. on Friday, January 16, 2015. Please include the name and phone number of the contact person. Questions relative to the proposed amended regulation for the refinery sector should be directed to Ms. Minh Pham at (909) 396-2613 or by email to mpham@aqmd.gov. Questions relative to the proposed amended regulation for the non-refinery sector should be directed to Mr. Kevin Orellana at (909) 396-3492 or by email to korellana@aqmd.gov.

The Public Hearing for the proposed amended regulation is scheduled for March 6, 2015. (Note: Public meeting dates are subject to change).

Date: December 4, 2014 **Signature:** Michael Krause

Michael Krause
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

Reference: California Code of Regulations, Title 14, §§ 15082 (a), 15103, 15365, and 15375

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
21865 Copley Drive, Diamond Bar, CA 91765-4178

NOTICE OF PREPARATION OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT

Project Title:
Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Project Location:
South Coast Air Quality Management District (SCAQMD) area of jurisdiction consisting of the four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin and the Mojave Desert Air Basin

Description of Nature, Purpose, and Beneficiaries of Project:
SCAQMD staff is proposing amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to reduce the allowable NOx emission limits based on current Best Available Retrofit Control Technology (BARCT) to achieve additional NOx emission reductions for the following industrial equipment and processes: 1) fluid catalytic cracking units (FCCUs); 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units (SRU/TGUs); 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines (ICEs); 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RECLAIM Trading Credits (RTCs) and NOx RTC adjustment factors for year 2016 and later. For clarity and consistency throughout the regulation, other minor changes are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions; and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions. The Initial Study identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Impacts to these environmental areas will be further analyzed in the Draft Program Environmental Assessment (PEA).

Lead Agency:	**Division:**
South Coast Air Quality Management District	Planning, Rule Development and Area Sources

NOP/IS and all supporting documentation are available at:	**or by calling:**	**or by accessing the SCAQMD's website at:**
SCAQMD Headquarters 21865 Copley Drive Diamond Bar, CA 91765	(909) 396-2039	http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2014

The NOP/IS is provided to the public through the following:

☑ Los Angeles Times (December 5, 2014)
☑ SCAQMD Public Information Center
☑ SCAQMD Mailing List & Interested Parties
☑ SCAQMD Website

NOP/IS Review Period (43 days):
December 5, 2014 – January16, 2015

The proposed project may have statewide, regional or areawide significance; therefore, a CEQA scoping meeting is required (pursuant to Public Resources Code §21083.9 (a)(2)) and will be held on January 8, 2015. See Scheduled Public Meeting Dates below for details.

Scheduled Public Meeting Dates (subject to change):
Working Group Meeting: January 7, 2015, 1:30 p.m.*;* SCAQMD Headquarters
CEQA and Socioeconomic Scoping Meeting: January 8, 2015, 10:00 a.m.*;* SCAQMD Headquarters
SCAQMD Governing Board Hearing: March 6, 2015, 9:00 a.m.; SCAQMD Headquarters

	Phone:	**Email:**	**Fax:**
Send CEQA Comments to: Ms. Barbara Radlein	(909) 396-2716	bradlein@aqmd.gov	(909) 396-3324
Direct Questions on Proposed Amended Regulation for Refinery Sector: Ms. Minh Pham	(909) 396-2613	mpham@aqmd.gov	(909) 396-3324
Direct Questions on Proposed Amended Regulation for Non-Refinery Sector: Mr. Kevin Orellana	(909) 396-3492	korellana@aqmd.gov	(909) 396-3324

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

INITIAL STUDY FOR:

DRAFT PROGRAM ENVIRONMENTAL ASSESSEMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

December 2014

SCAQMD No. 12052014BAR
State Clearinghouse No: To Be Determined

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APPENDICES

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Appendix C: Proposed Amended Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)

CHAPTER 1

PROJECT DESCRIPTION

Introduction

California Environmental Quality Act

Project Location

Project Background

Project Description

Technology Overview

Alternatives

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the District. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the District[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The Final 2012 AQMP concluded that reductions in emissions of particulate matter (PM), oxides of sulfur (SOx), oxides of nitrogen (NOx), and volatile organic compounds (VOC) are necessary to attain the state and national ambient air quality standards for ozone, and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5). Ozone, a criteria pollutant which has been shown to adversely affect human health, is formed when VOCs react with NOx in the atmosphere. VOCs, NOx, SOx (especially sulfur dioxide) and ammonia also contribute to the formation of PM10 and PM2.5.

The Basin is designated by the United States Environmental Protection Agency (EPA) as a non-attainment area for PM2.5 emissions because the federal PM2.5 standards have been exceeded. For this reason, the SCAQMD is required to evaluate all feasible control measures in order to reduce direct PM2.5 emissions, as well as PM2.5 precursors, such as NOx and SOx. The Final 2012 AQMP sets forth a comprehensive program for the Basin to comply with the federal 24-hour PM2.5 air quality standard, satisfy the planning requirements of the federal Clean Air Act, and provide an update to the Basin's commitments towards meeting the federal 8-hour ozone standard. In particular, the Final 2012 AQMP contains a multi-pollutant control strategy to achieve attainment with the federal 24-hour PM2.5 air quality standard with direct PM2.5 and NOx reductions identified as the two most effective tools in reaching attainment with the PM2.5 standard. The 2012 AQMP also serves to satisfy the recent requirements promulgated by the EPA for a new attainment demonstration of the revoked 1-hour ozone standard, as well as to provide additional measures to partially fulfill long-term reduction obligations under the 2007 8-hour Ozone State Implementation Plan (SIP).

As part of this ongoing PM2.5 reduction effort, SCAQMD staff is proposing amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements. The primary focus of the proposed project is to bring the NOx RECLAIM program up-to-date with the latest BARCT requirements while achieving the proposed NOx emission reductions in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM (e.g., at least three to five tons per day by 2023). The proposed project may achieve additional NOx emission reductions depending on the actual BARCT NOx emission control efficiencies. In addition, the proposed project is designed to implement both the Phase I and Phase II reduction commitments described in #CMB-01.

The proposed project may require installation of new or modification of existing NOx emission control equipment for the following industrial equipment and processes at NOx RECLAIM facilities: 1) fluid catalytic cracking units (FCCUs); 2) refinery boilers and heaters; 3) refinery

[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health and Safety Code, §§40400-40540).
[2] Health and Safety Code, §40460 (a).
[3] Health and Safety Code, §40440 (a).

gas turbines; 4) sulfur recovery units – tail gas treatment units (SRU/TGUs); 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines (ICEs); 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns, and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RECLAIM RTCs and NOx RTC adjustment factors for year 2016 and later. Other minor changes are proposed for clarity and consistency throughout the proposed amended regulation.

The proposed project is estimated to reduce at least three tons per day of NOx emissions or more starting in 2016. Despite this projected direct environmental benefit to air quality, this Initial Study, prepared pursuant to the California Environmental Quality Act (CEQA), identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. A Draft Program Environmental Assessment (PEA) will be prepared to analyze further whether the potential impacts to these environmental topics are significant. Any other potentially significant environmental impacts identified through this Notice of Preparation/Initial Study (NOP/IS) process will also be analyzed in the Draft PEA.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA), California Public Resources Code §21000 *et seq.*, requires environmental impacts of proposed projects to be evaluated and feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects to be identified and implemented. The lead agency is the "public agency that has the principal responsibility for carrying out or approving a project that may have a significant effect upon the environment" (Public Resources Code §21067). Since the SCAQMD has the primary responsibility for supervising or approving the entire project as a whole, it is the most appropriate public agency to act as lead agency (CEQA Guidelines[4] §15051 (b)).

CEQA requires that all potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures or alternatives, when an impact is significant.

Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989, and has been adopted as SCAQMD Rule 110 – Rule Adoption Procedures to Assure Protection and Enhancement of the Environment.

CEQA includes provisions for the preparation of program CEQA documents in connection with issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program, including adoptions of broad policy programs as distinguished from those prepared for specific types of projects such as land use projects (CEQA Guidelines §15168). A

[4] The CEQA Guidelines are codified at Title 14 California Code of Regulations, §15000 et seq.

program CEQA document also allows consideration of broad policy alternatives and program-wide mitigation measures at a time when an agency has greater flexibility to deal with basic problems of cumulative impacts. Lastly, a program CEQA document also plays an important role in establishing a structure within which CEQA review of future related actions can effectively be conducted. This concept of covering broad policies in a program CEQA document and incorporating the information contained therein by reference into subsequent CEQA documents for specific projects is known as "tiering" (CEQA Guidelines §15152).

A program CEQA document will provide the basis for future environmental analyses and will allow future project-specific CEQA documents, if necessary, to focus solely on the new effects or detailed environmental issues not previously considered. If an agency finds that no new effects could occur, or no new mitigation measures would be required, the agency can approve the activity as being within the scope of the project covered by the program CEQA document and no new environmental document would be required (CEQA Guidelines §15168 (c)(2)).

The proposed amendments to Regulation XX (PAReg XX) are considered a "project" as defined by CEQA. Specifically, PARegXX includes amendments to Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures), and Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures), to be discussed in further detail under "Project Description." PAReg XX will assure that the BARCT commitments for NOx emission reductions in the Final 2012 AQMP are achieved and maintained as well as provide an overall environmental benefit to air quality. However, SCAQMD's review of the proposed project also shows that implementation of PAReg XX may also have a significant adverse effect on the environment. Since PAReg XX may have statewide, regional or areawide significance, a CEQA scoping meeting is also required to be held for the proposed project pursuant to Public Resources Code §21083.9 (a)(2). Information regarding the CEQA scoping meeting can be found on the NOP.

In addition, since the proposed project: 1) is connected to the issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program (CEQA Guidelines §15168 (a)(3)); and, 2) contains a series of actions that can be characterized as one large project and the series of actions are related as individual activities that would be carried out under the same authorizing regulatory authority and having similar environmental effects which can be mitigated in similar ways (CEQA Guidelines §15168 (a)(4)), the appropriate type of CEQA document to be prepared for the proposed project will be a Program Environmental Assessment (PEA). The PEA is a substitute CEQA document, prepared in lieu of a program environmental impact report (EIR) (CEQA Guidelines §15252), pursuant to the SCAQMD's Certified Regulatory Program (CEQA Guidelines §15251 (l); codified in SCAQMD Rule 110). The PEA is also a public disclosure document intended to: 1) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental impacts of the proposed project; and, 2) be used as a tool by decision makers to facilitate decision making on the proposed project.

The first step of preparing a Draft PEA is to prepare a Notice of Preparation (NOP) with an Initial Study (IS) that includes an Environmental Checklist and project description. The Environmental Checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. The NOP/IS is also intended to provide information about the proposed project to other public agencies and interested parties prior to the release of the Draft PEA.

Thus, the SCAQMD as Lead Agency has prepared this NOP/IS for the proposed project. The initial evaluation in the NOP/IS identified the following topics as potentially being adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Written comments received on the scope of the environmental analysis will be considered when preparing the Draft PEA.

PROJECT LOCATION

The proposed amendments to Regulation XX would apply to equipment and processes operated at NOx RECLAIM facilities located throughout the entire SCAQMD jurisdiction. The SCAQMD has jurisdiction over an area of approximately 10,743 square miles, consisting of the four-county South Coast Air Basin (Basin) (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin (SSAB) and Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto mountains to the north and east. It includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of Riverside County and the SSAB that is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 1-1).

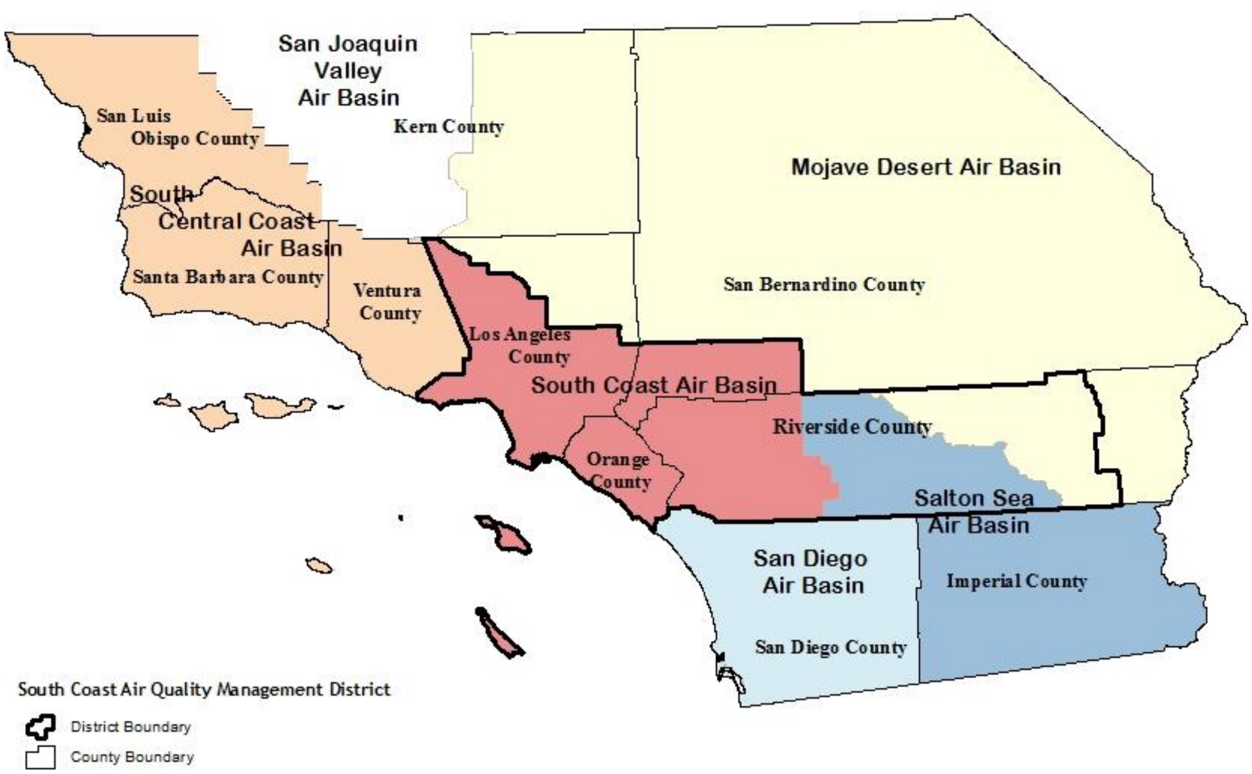

Figure 1-1: Southern California Air Basins

PROJECT BACKGROUND

On October 15, 1993, the SCAQMD Governing Board adopted Regulation XX, referred to herein as the RECLAIM program. Regulation XX is comprised of 15 rules which contain a declining market-based cap and trade mechanism to reduce NOx and SOx emissions from the largest stationary sources in the Basin and subsequently help meet air quality standards while providing facilities with the flexibility to seek the most cost-effective solution for achieving the required reductions. Instead of setting specific limits on each piece of equipment and each process that contributes to air pollution as is stipulated by traditional 'command-and-control' regulations, under the RECLAIM program each facility has a NOx and/or SOx annual emissions limit (allocation) and facility operators can decide what equipment, processes and materials they will use to reduce emissions to meet or go further below their annual emission limits. In lieu of reducing emissions, facility owners or operators may elect to use the trading market to purchase RTCs from other facilities that have reduced emissions below their annual target.

The portion of Regulation XX that focuses on reducing NOx emissions is referred to as "NOx RECLAIM" while the portion that focuses on reducing SOx emissions is referred to as "SOx RECLAIM." Regulation XX contains applicability requirements, NOx and SOx facility allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements for NOx and SOx sources located at RECLAIM facilities. The RECLAIM program started with 41 SOx facilities and 392 NOx facilities, but by the end of the 2005 compliance year, the program was populated with 33 SOx facilities and 304 NOx facilities. The population at the end of compliance year 2011 consists of 33 SOx facilities and 276 NOx facilities. The reduction in the number of facilities participating in the RECLAIM program since inception has been primarily due to facility shutdowns and/or consolidations.

Under the NOx RECLAIM program, the RECLAIM facilities were issued annual allocations of NOx emissions (also known as facility caps), which declined annually from 1993 until 2003 and remained constant after 2003, until SCAQMD staff conducted a BARCT reassessment for NOx in 2005. In 1993, annual allocations were issued to the RECLAIM facilities and the facility cap reflected BARCT in effect at that time. A BARCT reassessment is now necessary for NOx RECLAIM to assure that the participating facilities will continue to achieve emission reductions as expeditiously as possible to carry out the commitments in the 2012 AQMP. Under the RECLAIM program, the facilities have the flexibility to install air pollution control equipment, change method of operations, or purchase RTCs to meet BARCT levels.

To assure a more liquid market, as well as protect RECLAIM participants from price fluctuations that may be caused if all the RTCs expire at the same time, two trading cycles were established. Further, to balance emissions among the participating facilities in the RECLAIM program, the affected facilities were randomly divided into two cycles which vary by compliance year. That is, the Cycle 1 compliance year spans from January 1 to December 31 while the Cycle 2 compliance year spans from July 1 to June 30. A backstop level of $15,000 per ton was established to trigger program reevaluation.

Between compliance year 1994 and compliance year 1999, NOx emissions at RECLAIM facilities, in aggregate, were below the annual allocations, and the price of NOx RTCs remained relatively stable, ranging from $1,500 to $3,000 per ton. However, beginning June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RTC prices for both 1999 and 2000 compliance years. This was mainly due to an increased demand for power generation due to the California energy situation and the delay of installing NOx control equipment by many power plant operators, which resulted in the power-generating industry purchasing a large quantity of RTCs and depleting the supply of available RTCs. The average price of NOx RTCs for compliance year 2000, traded in the year 2000 increased sharply to over $45,000 per ton compared to the average price of $4,284 per ton traded in 1999. Since the RTC price for NOx exceeded the backstop price of $15,000 per ton, an evaluation of the RECLAIM program was triggered.

The Governing Board, at its October 2000 meeting, directed staff to examine the issues affecting the high price of NOx RTCs and recommend actions to stabilize NOx RTC prices. Additionally, the Governing Board directed the Executive Officer to form an Advisory Committee to provide input to staff regarding possible approaches to stabilize NOx RTC prices. Fourteen power producing facilities, each with a generating capacity of 50 megawatts (MW) or greater, purchased 67 percent of the NOx RTCs that were traded during compliance year 2000, suggesting that the increased demand and high prices of NOx RTCs were primarily due to the power producers. However, the annual allocations for all the power producers only accounted for approximately 14 percent of total RECLAIM annual allocations for compliance year 2000. At the same time, the RECLAIM program reached the 'cross-over point' where emissions equal allocations because many RECLAIM facilities, relying on previously low RTC prices, did not determine that it was more cost-effective to begin installing controls until after the RTC prices had peaked.

In recognition of the inherent lag time between the ability of facility operators to actually install and operate new control equipment, the Governing Board concluded that immediate changes to the RECLAIM program were necessary and, at the January 19, 2001 Board Meeting, directed staff to form a working group to develop and propose amendments to the RECLAIM program. The goal of the proposed amendments was to implement realistic, effective solutions to reduce and stabilize the prices of NOx RTCs. In May 2001, Regulation XX was amended to place trading restrictions on power producing facilities with the caveat that they could fully rejoin the trading market in the 2004 compliance year, provided that the Governing Board determined prior to July 2003 that their re-entry would not result in any negative effect on the remainder of the RECLAIM facilities or on California's energy security needs. In addition, the amendments also required the power plants to install BARCT and introduced credit generating rules. Lastly, a Mitigation Fee Program was established for the power plants to make up excess emissions through an option to pay a fee used to mitigate emissions through alternative means or programs.

Pursuant to these requirements, SCAQMD staff examined the energy security needs of California and the potential impacts on the RECLAIM market. The Governing Board determined that reentry of the power plants would not be expected to have a negative effect on California's energy security needs or on other RECLAIM facilities. Overall, power plants equipped with BARCT have reduced their NOx emission rates by approximately 80 percent or more from previously uncontrolled levels.

Based on these emission levels, the 14 power producing facilities are anticipated to emit a total of 1,395 tons per year of NOx and their total annual allocations are 1,705 tons per year for each year from 2003 to 2010. Further, the RTC holdings for the compliance years 2003 through 2010 range from 1,550 to 2,330 tons per year of NOx. This represented a surplus in the NOx RTC holdings at the time ranging from 155 to 935 tons per year. When considering the data relative to the typical annual operational capacity of a power producing unit at below 30 percent, except for 2001 when in-Basin units operated at 35 percent capacity, on average it would take all units operating at a capacity of 55 percent to cause a shortage in NOx RTCs. Therefore, based on the projected excess RTCs and typical operating capacities, power producers were then considered likely to be sellers of NOx RTCs in the RECLAIM program. For these reasons, the Governing Board at the June 6, 2003 public hearing, made the finding that lifting the trading restrictions for power producers in the RECLAIM trading market would not have a negative effect on the remainder of the RECLAIM facilities or on California's energy security needs. Subsequently, the Governing Board adopted proposed changes to RECLAIM Rules 2007, 2011, and 2012 at the December 5, 2003 public hearing which removed most of the trading restrictions on power producers. As a result, effective September 2004, the power producers were given unrestricted use of RTCs.

On January 7, 2005, amendments were made to the NOx RECLAIM program that resulted in a reduction of RTCs across the board by 7.7 tons per day, based on a BARCT evaluation. The RTCs were reduced from compliance years 2007 to 2011. The total RTCs in the NOx RECLAIM universe allocated in compliance year 2011 amounted to 26.5 tons per day. The audited emissions in compliance year 2011 were 20.01 tons per day, equating to 6.49 tons per day of excess holdings. The proposed RTC shave reduction will be based on compliance year 2011 activity levels for the affected facilities.

PROJECT DESCRIPTION

The proposed project will affect the following types of equipment and processes at the top NOx emitting facilities in the NOx RECLAIM program: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. The proposed amendments to the RECLAIM regulation contain the following key elements:

- Amend Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to establish procedures and criteria for reducing NOx RTCs and NOx RTC adjustment factors for year 2016 and later.
- Amend Rule 2002 to add new BARCT emission factors ending in 2021 for an assortment of equipment/process categories.
- Amend Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
- Amend Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
- Make administrative and other minor changes such as correcting typographical errors as well as clarifying and updating the rule and rule protocol language for consistency.

The following is a summary of the key proposed amendments. A copy of the proposed amended Rule (PAR) 2002 can be found in Appendix A of this NOP/IS. A copy of the proposed amended protocols for Rules 2011 and 2012 can be found in Appendices B and C, respectively.

PAR 2002

Annual Allocations for NOx and SOX and Adjustments to RTC Holdings – subdivision (f)

- Change compliance year "2011 and after" to "2011 to 2015" for the existing NOx RTC adjustment factors in subparagraph (f)(1)(A).
- Add new RTC adjustment factors to subparagraph (f)(1)(B) in order to achieve projected NOx emission reductions from NOx RTC holders beginning in compliance year 2016 and later. It should be noted that the proposed rule language describes an evenly distributed percent of NOx RTC reductions applicable to all RECLAIM facilities. However, an alternate approach of distributing the NOx RTC reductions among the top NOx RECLAIM facilities would not be precluded.
- Clarify procedures for entering the RECLAIM program after January 7, 2005 in subparagraph (f)(1)(I) to reflect the new RTC adjustment factors added to subparagraph (f)(1)(B).

RTC Reduction Exemption – subdivision (i)

- Clarify paragraph (i)(1) that the RTC reduction exemption does not include RTC holdings for compliance year 2016 and thereafter.
- Clarify subparagraph (i)(1)(B) that the application for an RTC reduction exemption needs to demonstrate that the reported emissions for Compliance Year 2013 are not from equipment listed in existing Table 3 or new Table 6 and that the achieved emission rates are less than the emission factors listed in existing Table 3 or new Table 6, whichever is lower.
- Clarify subparagraph (i)(1)(C) that the application for an RTC reduction exemption needs to demonstrate that the RTCs for Compliance Year 2016 have never been transferred or sold by the facility.
- Clarify clause (i)(1)(D)(i) to allow the exclusion of control costs for any equipment listed in existing Table 3 or new Table 6.
- Clarify paragraph (i)(3) that an application for an RTC reduction exemption shall be submitted no later than six months after the adoption of the proposed project.
- Clarify paragraph (i)(8) to require a facility qualifying for an exemption to include emissions from equipment listed in existing Table 3 or new Table 6 in its Annual Permit Emission Program (APEP) report.

RECLAIM NOx 2021 Ending Emission Factors – new Table 6

- Add new BARCT emission factors ending in 2021 for certain boilers and heaters, cement kilns, FCCUs, gas turbines, container glass melting furnaces, permitted ICEs, metal heat treating furnaces, petroleum coke calciners, sodium silicate furnaces, and SRU/TGUs.

Rule 2011 Appendix A (SOx Protocol for Rule 2011)

Attachment C - Quality Assurance and Quality Control Procedures

- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of a major source.
- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of an electrical generating facility (EGF).

Rule 2012 Appendix A (NOx Protocol for Rule 2012)

Attachment C - Quality Assurance and Quality Control Procedures

- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of a major source.
- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of an electrical generating facility (EGF).

TECHNOLOGY OVERVIEW

NOx Emission Sources

The NOx RECLAIM program currently consists of 276 facilities as of the 2011 compliance year. Of these, 139 facilities operate NOx emitting equipment for which there is no new BARCT identified. For this reason, the proposed project will focus on reducing NOx emissions from the major and large sources of the top emitters of NOx for which new BARCT has been identified (e.g., facilities that emit 85 percent of the total NOx emissions from all RECLAIM facilities). However, a BARCT assessment for approximately ICEs that are operating at the 139 remaining NOx RECLAIM facilities would not be precluded from the proposed project. The following are the top emitters of NOx in the RECLAIM program:

- Six refineries owned by five companies operate FCCUs, refinery boilers and heaters, refinery gas turbines, and SRU/TGUs: Tesoro (two locations: Wilmington and Carson); Phillips 66 (two locations: Wilmington and Carson); Chevron; ExxonMobil; and, Ultramar (also referred to as Valero)
- One coke calciner plant: Tesoro (Wilmington location)
- One cement manufacturing plant: California Portland Cement (CPCC)
- One container glass manufacturing plant: Owens-Brockway Glass Container Inc.
- One sodium silicate manufacturing plant: PQ Corporation
- One steel plant operating two metal heat treating furnaces rated > 150 million British Thermal Units per hr (mmBTU/hr): California Steel
- Seven facilities operating gas turbines: Southern California Gas Company, SDGE, THUMS Long Beach, Wheelabrator Norwalk Energy, LA City Dept. of Airports, Tin Inc., and Berry Petroleum
- Three facilities operating IC Engines: SDGE and Southern California Gas Company (two facilities)

Of the above-listed facilities, six refineries operate one FCCU each, one SRU/TGU each, and a multitude of refinery process heaters and boilers and refinery gas turbines. The quantity of major and large source NOx emissions from the six refineries alone comprises approximately 54 percent of the total NOx emitted from the universe of RECLAIM facilities. The major and large sources belonging to non-refineries among the top NOx emitting facilities emit 25 percent of the RECLAIM universe's total. The remaining 11 percent of emissions that contribute to the 85 percent total come from process units and equipment that is exempt from SCAQMD Rule 219 - Equipment Not Requiring A Written Permit Pursuant To Regulation II.

Combustion Equipment

To appreciate the mechanics of NOx control equipment and techniques, it is necessary to first understand how NOx emissions are generated from the affected equipment and processes. Combustion is a high temperature chemical reaction resulting from burning a gas, liquid, or solid fuel (e.g., natural gas, diesel, fuel oil, gasoline, propane, and coal) in the presence of air (oxygen and nitrogen) to produce: 1) heat energy; and, 2) water vapor or steam. An ideal combustion reaction is when the entire amount of fuel needed is completely combusted in the presence of air so that only carbon dioxide (CO2) and water are produced as by-products. However, since fuel contains other components such as nitrogen and sulfur plus the amount of air mixed with the fuel can vary, in practice, the combustion of fuel is not a "perfect" reaction. As such, uncombusted fuel plus smog-forming by-products such as NOx, SOx, carbon monoxide (CO), and soot (solid carbon) can be discharged into the atmosphere.

Of the total NOx emissions that can be generated, there are two types of NOx formed during combustion: 1) thermal NOx; and, 2) fuel NOx. Thermal NOx is produced from the reaction between the nitrogen and oxygen in the combustion air at high temperatures while fuel NOx is formed from a reaction between the nitrogen already present in the fuel and the available oxygen in the combustion air. As the source of nitrogen in fuel is more prevalent in oil and coal, and is negligible in natural gas, the amount of fuel NOx generated is dependent on fuel type. For example, with oil that contains significant amounts of fuel-bound nitrogen, fuel NOx can account for up to 50 percent of the total NOx emissions generated. Though boilers, process heaters, petroleum coke calciners, FCCUs, gas turbines, and other miscellaneous equipment have varying purposes in commercial, industrial, and utility applications, at a minimum, they all generate thermal NOx as a combustion by-product. The following provides a brief description of the various types of existing combustion equipment that may be affected by the proposed amendments to Regulation XX and subsequently retrofitted with NOx control equipment.

REFINERY CATEGORY

Refinery Process Heaters and Boilers

Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking.

A process heater is a type of combustion equipment that burns liquid, gaseous, or solid fossil fuel for the purpose of transferring heat from combustion gases to heat water or process streams. Process heaters are not kilns or ovens used for drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

A typical boiler, also referred to as a steam generator, is a steel or cast-iron pressure vessel equipped with burners that combust liquid, gas, or solid fossil fuel to produce steam or hot water. Boilers are classified according to the amount of energy output in millions of British Thermal Units per hour (mmBTU/hr), the type of fuel burned (natural gas, diesel, fuel oil, etc.), operating steam pressure in pounds per square inch (psi), and heat transfer media. In addition, boilers are further defined by the type of burners used and air pollution control techniques. The burner is where the fuel and combustion air are introduced, mixed, and then combusted.

There are about 23 boilers and 189 heaters in the refineries classified as major or large NOx sources. There are a total of 212 boilers and heaters classified as major and large NOx sources at the refineries. Collectively, the 212 boilers and heaters emitted approximately 7.39 tons per day in 2011.

Refinery process heaters and boilers are primarily fueled by refinery gas, one of several products generated at the refinery. In addition, most of the refinery process heaters and boilers are designed to also operate on natural gas, but liquid or solid fuels are rarely used. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

Commercially available technologies for controlling NOx from refinery boilers and process heaters are selective catalytic reduction (SCR), Great Southern Flameless Heaters, and LoTOx^{TM} applications with scrubbers. Other potential technologies on the horizon are ClearSign, Cheng Low NOx and KnowNOx^{TM}. All of these control technologies can be designed to reach two parts per million by volume (ppmv) NOx at three percent oxygen. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that each refinery may rely on any of these control technologies in order to comply with the refinery process heaters and boilers portion of the proposed project.

<u>Refinery Gas Turbines</u>

Gas turbines are used in refineries to produce both electricity and steam. Refinery gas turbines are typically combined cycle units that use two work cycles from the same shaft operation. Refinery gas turbines also have an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are power plant turbines (turbines that produce solely electric utility power) and some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam. There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tons per day of NOx in 2011.

Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40 percent and combined-cycle efficiencies of 60 percent. The existing gas turbines operating at the refineries are rated from seven MW to 83 MW. Most of the refinery gas turbines are operated with duct burners, heat recovery steam generator (HRSG), SCR, and CO catalysts. In addition, some refinery gas units utilize water or steam injection, Ammonia Slip Catalysts (ASC), Cheng Low NOx, and Dry Low Emissions (DLN or DLE) combustors. Figure 1-2 shows a typical layout of a combined cycle utility gas turbine with a duct burner, HRSG, and control system.

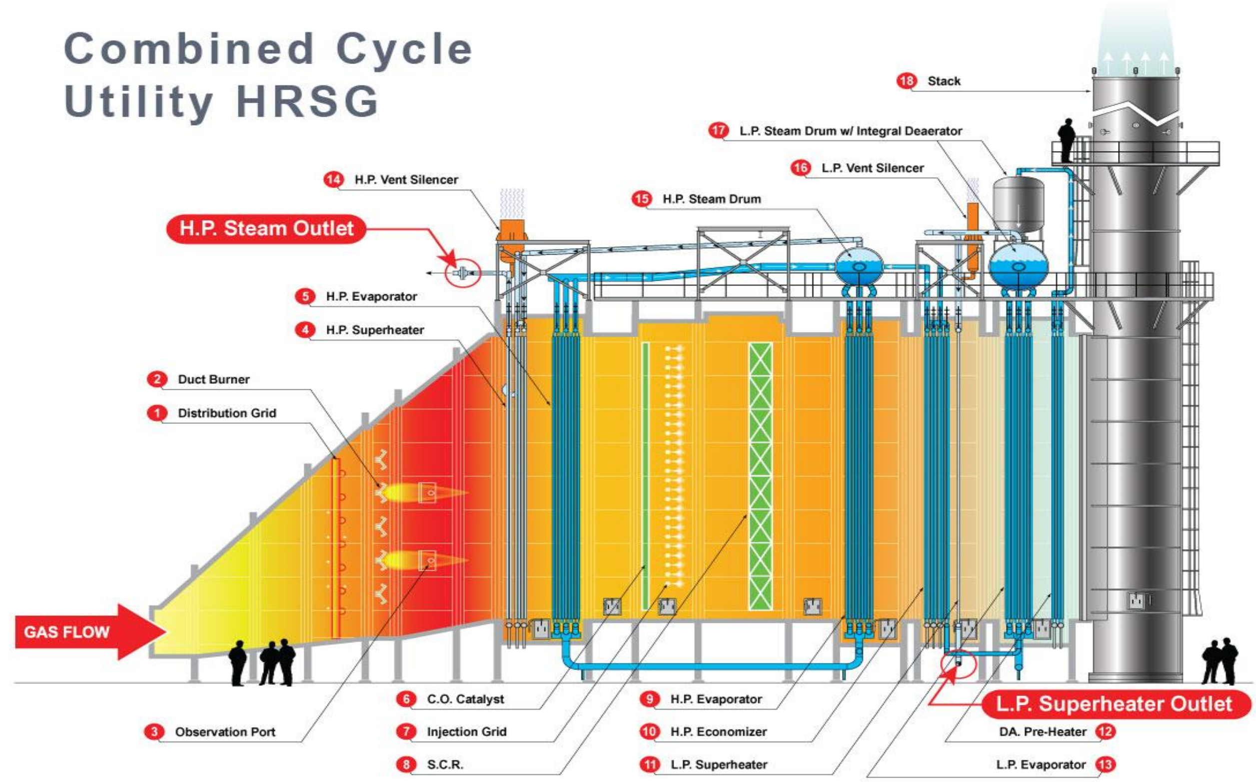

Figure 1-2: Gas Turbine with Duct Burner

The type of NOx control option to be utilized for refinery gas turbines will depend on each refinery's individual operations and the current control technologies and techniques in place. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that each refinery may rely on any of these control technologies in order to comply with the refinery gas turbines portion of the proposed project.

Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGTUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal. A typical sulfur removal or recovery system will include a sulfur recovery unit (e.g., Claus unit) followed by a tail gas treatment unit (e.g., amine treating) for maximum removal of hydrogen sulfide (H_2S). A Claus unit consists of a reactor, catalytic converters and condensers. Two chemical reactions occur in a Claus unit. The first reaction occurs in the reactor, where a portion of H_2S reacts with air to form sulfur dioxide (SO_2) followed by a second reaction in the catalytic converters where SO_2 reacts with H_2S to form liquid elemental sulfur. Side reactions producing carbonyl sulfide (COS) and carbon disulfide (CS_2) can also occur. These side reactions are problematic for Claus plant operators because COS and CS_2 cannot be easily converted to elemental sulfur and carbon dioxide. Liquid sulfur is recovered after the final condenser. The combination of two converters with two condensers in series will generally remove as much as 95 percent of the sulfur from the incoming acid gas. To increase removal efficiency, some newer sulfur recovery units may be designed with three to four sets of converters and condensers.

To recover the remaining sulfur compounds after the final pass through the last condenser, the gas is sent to a tail gas treatment process such as a SCOT or Wellman-Lord treatment process. For example, the SCOT tail gas treatment is a process where the tail gas is sent to a catalytic reactor and the sulfur compounds in the tail gas are converted to H_2S. The H_2S is absorbed by a solution of amine or diethanol amine (DEA) in the H_2S absorber, steam-stripped from the absorbent solution in the H_2S stripper, concentrated, and recycled to the front end of the sulfur recovery unit. This approach typically increases the overall sulfur recovery efficiency of the Claus unit to 99.8 percent or higher. However, the fresh acid gas feed rate to the sulfur recovery unit is reduced by the amount of recycled stream, which reduces the capacity of the sulfur recovery unit. The residual H_2S in the treated gas from the absorber is typically vented to a thermal oxidizer where it is oxidized to sulfur dioxide (SO_2) before venting to the atmosphere.

The Wellman-Lord tail gas treatment process is when the sulfur compounds in the tail gas are first incinerated to oxidize to SO_2. After the incinerator, the tail gas enters a SO_2 absorber, where the SO_2 is absorbed in a sodium sulfite (Na_2SO_3) solution to form sodium bisulfite ($NaHSO_3$) and sodium pyrosulfate ($Na_2S_2O_5$). The absorbent rich in SO_2 is then stripped, and the SO_2 is recycled back to the beginning of the Claus unit. The residual sulfur compounds in the treated tail gas from the SO_2 absorber is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before venting to the atmosphere. NOx is a by-product of operating the incinerator.

There are three main strategies that can be employed to further reduce NOx emissions from each SRU/TGU operating at the six refineries: 1) increase the efficiency of the sulfur recovery unit; 2) improve the efficiency of the tail gas treatment process; and, 3) install a wet gas scrubber (WGS) as an alternative to the thermal oxidizer[5]. The type of NOx control option to be utilized in response to this portion of the proposed project will depend on each refinery's individual operations and the current control technologies and techniques in place. Commercially available control technologies for NOx emissions are SCR, LoTOx™ with scrubber, and KnowNOx™. While SCR is considered as a high temperature NOx reduction technology, LoTOx™ and KnowNOx™ technologies are known for low temperature multi-pollutant control systems since they can be integrally connected with a WGS to reduce NOx, SOx, PM, VOC, hazardous air pollutants (HAPs), and other toxic compounds. For a full description of these control technologies, see the NOx Control Technologies section.

The Draft PEA will evaluate the possibility that each refinery may rely on any of these control technologies in order to comply with the SRU/TGU portion of the proposed project.

<u>Petroleum Coke Calciner</u>

Petroleum coke, the heaviest portion of crude oil, cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as "green coke," a commodity. To improve the quality of the product, if the green coke has a low metals content, it will be sent to a calciner to make calcined petroleum coke. Calcined petroleum coke can be used to make anodes for the aluminum, steel, and titanium smelting industry. If the green coke has a high metals content, it is used as fuel grade coke by the fuel, cement, steel, calciner and specialty chemicals industries.

[5] All six refineries have thermal oxidizers at the end of their tail gas treatment units.

As shown in Figure 1-3, the process of making calcined petroleum coke begins when the green coke feed produced by the delayed coker unit is screened and transported to the calciner unit where it is stored in a covered coke storage barn. The screened and dried green coke is introduced into the top end of a rotary kiln and is tumbled by rotation under high temperatures that range between 2000 and 2500 degrees Fahrenheit (^oF). The rotary kiln relies on gravity to move coke through the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or fuel oil. As the green coke flows to the bottom of the kiln, it rests in the kiln for approximately one additional hour to eliminate any remaining moisture, impurities, and hydrocarbons. Once discharged from the kiln, the calcined coke is dropped into a cooling chamber, where it is quenched with water, treated with de-dusting agents to minimize dust, carried by conveyors to storage tanks. Eventually, the calcined coke is transported by truck to the Port of Long Beach for export, or is loaded onto railcars for shipping to domestic customers. As the green coke is processed under high heat conditions in the rotary kiln, NOx emissions are generated. NOx is also generated from combusting fuel oil to generate high heating values in the rotary kiln.

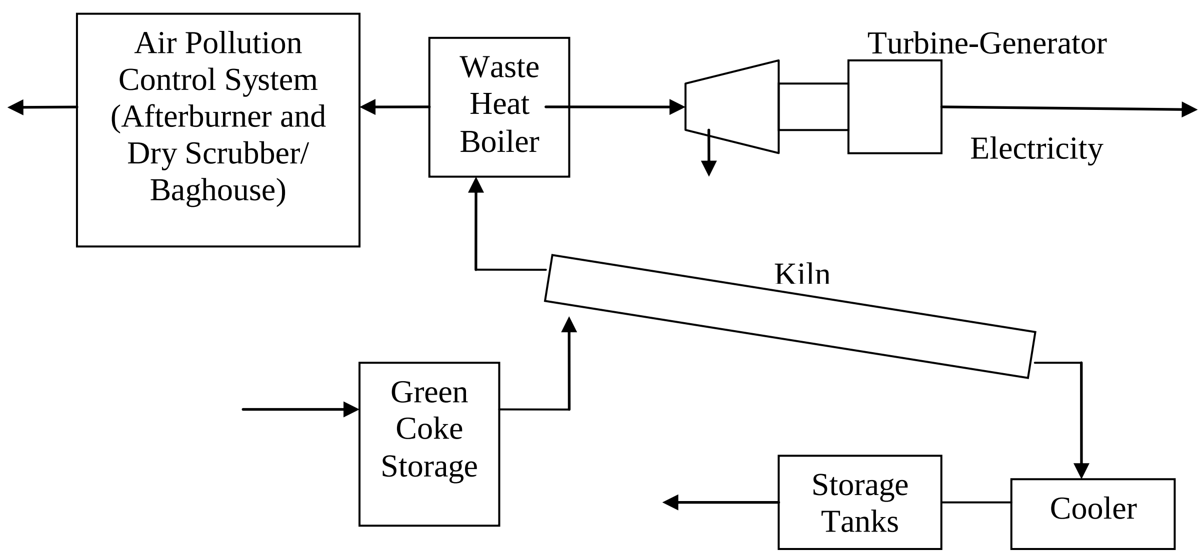

Figure 1-3: Coke Calciner Process

The Tesoro Wilmington coke calciner is only petroleum coke calciner in the Basin and produces approximately 400,000 short tons per year of calcined products. This petroleum coke calciner is a global supplier of calcined coke to the aluminum industry, and fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses. The existing control system also includes a spray dryer, a reverse-air baghouse, a slurry storage system, a slurry circulating system, and a pneumatic conveying system. Calcium hydroxide (CaOH) slurry is the absorbing medium for SO_2 control.

There are two commercially available multi-pollutant control technologies for the low temperature removal of NOx emissions from the coke calciner: 1) LoTOx^{TM} with scrubber; and, 2) UltraCat. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for the coke calciner in response to the proposed project will depend on this facility's individual operations and the current control technologies and techniques in place. Thus, the Draft PEA will evaluate the possibility that operators of the petroleum coke calcining facility may rely on either of the above-mentioned control technologies to further control NOx emissions in order to comply with the BARCT requirements for the petroleum coke calcining portion of the proposed project.

<u>FCCUs</u>

The purpose of an FCCU at a refinery is to convert or "crack" heavy oils (hydrocarbons), with the assistance of a catalyst, into gasoline and lighter petroleum products. Each FCCU consists of three main components: a reaction chamber, a catalyst regenerator and a fractionator. All six refineries each operate one FCCU.

As shown in Figure 1-4, the cracking process begins in the reaction chamber where fresh catalyst is mixed with pre-heated heavy oils (crude) known as the fresh feed. The catalyst typically used for cracking is a fine powder made up of tiny particles with surfaces covered by several microscopic pores. A high heat-generating chemical reaction occurs that converts the heavy oil liquid into a cracked hydrocarbon vapor mixed with catalyst. As the cracking reaction progresses, the cracked hydrocarbon vapor is routed to a distillation column or fractionator for further separation into lighter hydrocarbon components than crude such as light gases, gasoline, light gas oil, and cycle oil.

Towards the end of the reaction, the catalyst surface becomes inactive or spent because the pores are gradually coated with a combination of heavy oil liquid residue and solid carbon (coke), thereby reducing its efficiency or ability to react with fresh heavy liquid oil in the feed. To prepare the spent catalyst for re-use, the remaining oil residue is removed by steam stripping. The spent catalyst is later cycled to the second component of the FCCU, the regenerator, where hot air burns the coke layer off of the surface of each catalyst particle to produce reactivated or regenerated catalyst. Subsequently, the regenerated catalyst is cycled back to the reaction chamber and mixed with more fresh heavy liquid oil feed. Thus, as the heavy oils enter the cracking process through the reaction chamber and exit the fractionator as lighter components, the catalyst continuously circulates between the reaction chamber and the regenerator.

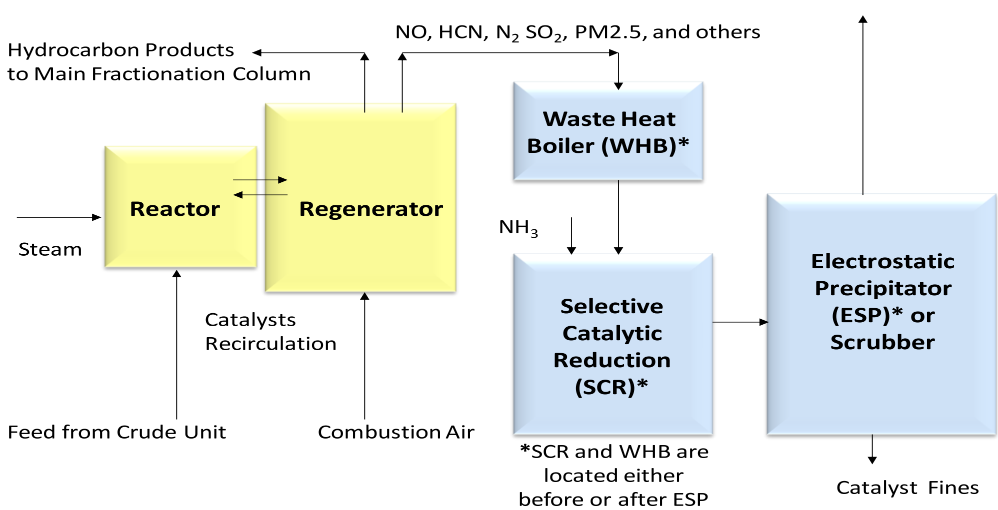

Figure 1-4: Simplified Schematic of FCCU Process

During the regeneration cycle, large quantities of catalyst are lost in the form of catalyst fines or particulates thus making FCCUs a major source of primary particulate emissions (PM10 and

PM2.5) at refineries. In addition, particulate (PM) precursor emissions such as SOx (because crude oil naturally contains sulfur) and NOx, additional secondary particulates (i.e., formed as a result of various chemical reactions), plus carbon monoxide (CO) and carbon dioxide (CO_2) are produced due to coke burn-off during the regenerator process.

Approximately 90 percent of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is then burned-off in the regenerator. This portion of the NOx is called "fuel" NOx. "Fuel" NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10 percent of the NOx generated from the FCCUs are "thermal" NOx which is generated in the high temperature zones in the regenerator, and "prompt" NOx generated from the reaction between nitrogen and oxygen in the combustion air. The potential available control technologies to reduce NOx emissions from a FCCU are: 1) SCR; 2) LoTOx™ with scrubber; and/or, 3) NOx reducing additives.

The type of NOx control option to be utilized for FCCUs in response to the proposed project will depend on each refinery's individual operations and the current control technologies and techniques in place. Thus, the Draft PEA will evaluate the possibility that refinery operators of the FCCUs may rely on the above-mentioned control technologies to further control NOx emissions in order to comply with the BARCT requirements for FCCUs.

NON-REFINERY / NON-POWER PLANT CATEGORY

Portland Cement Kilns

In the NOx RECLAIM program, there is one facility (CPCC) with two cement kilns capable of producing gray cement from limestone, sand, shale, and clay raw materials. The CPCC facility, under normal operation, has typically been among the highest NOx emitters in the RECLAIM program. However, on November 20, 2009, CPCC operators announced the shutdown of both cement kilns. CPCC operators indicated that the shutdown is not permanent to the extent that when the economy improves, they plan to bring the cement kilns back on-line.

The manufacturing of gray Portland cement follows a four-step process of: 1) acquiring raw materials; 2) preparing the raw materials to be blended into a raw mix; 3) pyroprocessing of the raw mix to make clinker (e.g., lumps of limestone and clay); and, 4) grinding and milling clinker into cement. The raw materials used for manufacturing cement include calcium, silica, alumina and iron, with calcium having the highest concentration. These raw materials are obtained from a limestone quarry for calcium, sand for silica; and shale and clay for alumina and silica.

The raw materials are crushed, milled, blended into a raw mix and stored. Primary, secondary and tertiary crushers are used to crush the raw materials until they are about ¾-inch or smaller in size. Raw materials are then conveyed to rock storage silos. Belt conveyors are typically used for this transport. Roller mills or ball mills are used to blend and pulverize raw materials into fine powder. Pneumatic conveyors are typically used to transport the fine raw mix to be stored in silos until it is ready to be pyroprocessed.

The pyroprocess in a kiln consists of three phases during which clinker is produced from raw materials undergoing physical changes and chemical reactions. The first phase in a kiln, the drying and pre-heating zone, operates at a temperature between 70 ^{o}F and 1650 ^{o}F and evaporates any remaining water in the raw mix of materials entering the kiln. Essentially this is the warm-up phase which stabilizes the temperature of the refractory fire brick inside the mouth opening of the kiln. The second phase, the calcining zone, operates at a temperature between 1100 ^oF and 1650 ^oF and converts the calcium carbonate from the limestone in the kiln feed into calcium oxide and releases carbon dioxide. During the third phase, the burning zone operates on average at 2200 ^oF to 2700 ^oF (though the flame temperature can exceed 3400 ^oF) during which several reactions and side reactions occur. The first reaction is calcium oxide (produced during the calcining zone) with silicate to form dicalcium silicate and the second reaction is the melting of calcium oxide with alumina and iron oxide to form the liquid phase of the materials. Despite the high temperatures, the constituents of the kiln feed do not combust during pyroprocessing. As the materials move towards the discharge end of the kiln, the temperature drops and eventually clinker nodules form and volatile constituents, such as sodium, potassium, chlorides, and sulfates, evaporate. Any excess calcium oxide reacts with dicalcium silicate to form tricalcium silicate. The red hot clinker exits the kiln, is cooled in the clinker cooler, passes through a crusher and is conveyed to storage for protection from moisture. Since clinker is water reactive, if it gets wet, it will set into concrete.

Heat needed to operate CPCC's kilns is supplied through the combustion of different fuels such as coal, coke, oil, natural gas, and discarded automobile tires. The combustion gases are vented to a baghouse for dust control, and the collected dust is returned to the process or recycled if they meet certain criteria, or is discarded to landfills. CPCC does not currently have any post-combustion control for NOx emissions.

NOx emissions from the cement kilns are generated from the following: 1) from combusting fuel to generate high heating values in the kilns; and, 2) oxidation of sulfides (e.g., pyrites) in the raw materials entering the cement kiln. As is the case with CPCC, long, dry cement kilns have achieved NOx reductions to the 2000 (Tier 1) level by utilizing low NOx burners and mid-kiln firing with tire-derived fuel (TDF). With TDF, whole tires are introduced at an inlet location about midway along the kiln's calcining zone. TDF lowers NOx emissions by lowering the flame temperatures and reducing thermal NOx with the introduction of a slower burning fuel.

In the event that CPCC operators decide to fire up its kilns, the type of NOx control technology to be utilized to comply with the proposed project will depend on CPCC's individual operations and how the kilns will function with the current control technologies and techniques in place at CPCC (e.g., the baghouse). The potential available control technologies to reduce NOx emissions from cement kilns are: 1) SCR with or without a WGS; 2) UltraCat; or, 3) SNCR. For a full description of these control technologies, see the NOx Control Technologies section. Thus, the Draft PEA will evaluate the possibility that CPCC operators may rely on the above-mentioned control technologies to further control NOx emissions from cement kilns to comply with the proposed project.

Container Glass Melting Furnaces

In the NOx RECLAIM program there is one facility among the top NOx emitting facilities that operates glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

A container glass melting furnace is the main equipment used for manufacturing glass products, such as bottles, glass wares, pressed and blown glass, tempered glass, and safety glass. The manufacturing process consists of four phases: 1) preparing the raw materials; 2) melting the mixture of raw materials in the furnace; 3) forming the desired shape; and, 4) finishing the final product. Raw materials, such as sand, limestone, and soda ash, are crushed and mixed with cullets (recycled glass pieces) to ensure homogeneous melting. The raw materials mixture is then conveyed to a continuous regenerative side-port melting furnace. As the mixture enters the furnace through a feeder, it melts and blends with the molten glass already in the furnace, and eventually flows to a refiner section, to a forming machine, and then, to annealing ovens. The final products undergo inspection, testing, packaging and storage. Any damaged or undesirable glass is transferred back to be recycled as cullet suitable for remelting.

NOx is generated from a container glass melting furnace in two ways: 1) during the decomposition of the silica in the raw materials; and, 2) from combusting fuel to generate high heating values in the furnace. The container glass melting furnace contributes over 99 percent of the total NOx emissions from a glass manufacturing plant. To effectively achieve the largest reduction of NOx emissions, SCR and UltraCat technologies are commercially available options for treating the flue gas of glass melting furnaces. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the glass melting furnace portion of the proposed project.

Sodium Silicate Furnace

In the NOx RECLAIM program, there is only one facility that produces sodium silicate in a melting furnace. Sodium silicate, a type of glass with a wide variety of industrial uses, should not to be confused with container or flat glass. Sodium silicate exists in a solid or liquid form, depending on the temperature. The combination of heating a batch-fed mixture of soda ash and sand causes the materials to produce sodium silicate and CO_2. NOx emissions are also created from combusting fuel needed to heat the furnace. In order to generate high heating values, the furnace is fired by several natural gas-fired burners. The flue gas then exits the furnace via a stack into the atmosphere.

Approximately 15 to 20 percent of NOx emission reductions can be achieved by utilizing blower air staging to lower the flue gas temperature in the furnace. To effectively achieve the largest reduction of NOx emissions, however, SCR technology is best suited for treating the flue gas of sodium silicate furnaces.

In addition, UltraCat, an alternate to SCR technology, is also available for multi-pollutant control. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the sodium silicate furnace portion of the proposed project.

Metal Heat Treating Furnaces

A metal melting furnace burns liquid or gaseous fuel to generate enough pre-heated air at a temperature high enough to melt solid metal and into a liquid molten consistency and to maintain the metal in a liquid state until it is ready for later use. The types of furnaces that are used for metal melting are reverberatory, cupola, induction, direct arc furnaces, sweat furnaces, and refining kettles. The burner flame and combustion products come in direct contact with the metal.

Heat treating operations are directly related to the metal producing and secondary metal processing industries. Materials handled by the heat treating industry are a variety of products provided by manufacturers that are used by other manufacturers, to make consumable or usable products. Typical materials used for heat treating are iron, steel, ferro-alloys, glass, and other nonferrous metals. Heat treatment furnaces are used for activities that include forging, hardening, tempering, annealing, normalizing, sintering, and case hardening of steels and solution and heat treatment of corrosion resistant and aluminum metals. Kilns are not considered heat treating furnaces. Among the top NOx emitting facilities in the NOx RECLAIM program, there is only one facility that processes steel in two metal heat furnaces with individual heat ratings above 150 mm BTU/hr.

As with all combustion sources, the type of burner used can affect the emissions. Some burners are lower NOx emitting than others. But for these types of furnaces, there are often dozens of burners that cumulatively require a high heat input. To achieve higher efficiency and to consume less fuel, recuperative and regenerative burners are used. These burners employ the principle of using preheated inlet air which is heated by the exhaust gases for more efficient combustion. However, to effectively achieve a substantial NOx reduction from these metal heat treating furnaces, SCR is the technology that is best suited for the flue gas treatment of NOx. For a full description of these control technologies, see the NOx Control Technologies section.

The Draft PEA will evaluate the possibility that the operator of the metal heat treating furnaces may rely on a combination of recuperative and regenerative burners along with SCR technology to further control NOx emissions in order to comply with the BARCT requirements for the metal heat treating furnace portion of the proposed project.

<u>Gas Turbines (Non-Refinery/Non-Power Plant)</u>
Stationary gas turbines are used primarily to drive compressors or to generate power. Gas turbines operate either in simple cycle or combined cycle. Simple cycle units use the mechanical energy of shaft work that is transferred to and used by a gas compressor, for example, or to run an electrical generator to produce electricity. A combined cycle unit adds an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Combined cycle units are more efficient due to their use of two work cycles from the same shaft operation. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are not power plant turbines (turbines that produce solely electric utility power). Some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam.

Among the top non-power plant NOx emitting facilities in the RECLAIM universe, there are twenty gas turbines that are either major or large source units. Four of these units are currently utilizing some level of NOx control along with SCR. Six of these units are operated on an offshore oil drilling platform (outer continental shelf, or OCS). The OCS turbines, which are fired on diesel or process gas, have the highest NOx emission concentrations in this source category. Four of the OCS units with lower NOx parts per million (ppm) concentrations currently are equipped with SCR systems.

There are several methods of NOx control for gas turbines, with differing levels of reduction, such as steam or water injection, dry low emissions (DLE or DLN), and SCR. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for gas turbines will depend on the facility's individual operations and the current control technologies and techniques in place. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the stationary gas turbine portion of the proposed project.

Internal Combustion Engines (Non-Refinery/Non-Power Plant)
Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate power. There are generally two types of engines, spark-ignited (SI) or compression ignited (CI) engines. SI engines ignite the air/fuel mixture with a spark while CI engines use the heat of compression to ignite the fuel that is injected into the combustion chamber. Engines can run at either stoichiometrically rich burn or lean burn conditions, depending on the air to fuel ratio. Rich burn combustion corresponds to an air-to-fuel ratio that is fuel-rich while lean burn combustion corresponds to a fuel-lean air-to-fuel ratio. Small SI engines typically run as rich burn, but many larger units as well as CI engines operate under lean burn conditions. For lean burn engines, more air is inducted than is required for complete combustion and the resultant exhaust oxygen level is high (over five percent). Rich burn engines typically operate very close to stoichiometric conditions by drawing only the necessary air to combust the fuel. SI engines are typically fired on gaseous fuels such as natural gas, while CI engines are fired on liquid fuels such as diesel.

Among the top NOx emitting facilities in the RECLAIM universe, there are 31 engines that are either major or large source units. Currently, there are nine rich burn engines equipped non-selective catalytic reduction (NSCR). Of the remaining 22 engines, there are 16 SI lean burn engines units and six CI lean burn units. The CI lean burn units are all operated on an offshore oil drilling platform (outer continental shelf, or OCS). The engine sizes range from a little over 700 brake horsepower (bhp) to 5,500 bhp. Diesel-fueled CI engines have the highest NOx emission concentrations in this source category while two-stroke SI engines have higher NOx emissions than four-stroke SI engines since the higher efficiencies in two-stroke engines translate to a hotter combustion temperature that can create more NOx.

Because the flue gas from rich burn engines has typically very low excess oxygen, NOx reductions can be achieved with NSCR technology. For lean burn exhaust with higher oxygen content, SCR is more effective at reducing NOx emissions. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for stationary ICEs will depend on the facility's individual operations and the current control technologies and techniques in place. For the ICEs operating at the 139 remaining NOx RECLAIM faculties, the ICEs would also need to meet the BARCT levels on a programmatic basis. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the stationary ICEs portion of the proposed project.

NOx Control Technologies

As reducing NOx emissions is the main objective of the currently proposed amendments to the RECLAIM program, there are two primary approaches for reducing NOx emissions: 1) by combustion control techniques that minimize the amount of NOx formed by the combustion equipment; or, 2) by installing a device that controls the NOx after it has been generated or post-combustion. On an equipment/process basis, Table 1-1 summarizes the potential control technologies that will be considered as part of the BARCT analysis for the proposed project. The following discussions will elaborate on the various technologies listed in Table 1-1.

Table 1-1
BARCT Control Technology Options for Top NOx Emitting Equipment/Processes

Equipment/Process	BARCT Control Technology Options
FCCUs	1. SCR 2. LoTOx^{TM} with scrubber 3. NOx reducing additives
Refinery Process Heaters and Boilers	1. SCR 2. LoTOx^{TM} with scrubber 3. KnowNOx^{TM} with scrubber 4. Great Southern Flameless Heaters 5. ClearSign 6. Cheng Low NOx
Refinery Gas Turbines	1. SCR 2. Ammonia Slip Catalyst (ASC) 3. CO Catalyst 4. Dry Low Emissions (DLE or DLN) 5. Cheng Low NOx
SRU/TGUs	1. SCR 2. LoTOx^{TM} with scrubber 3. KnowNOx^{TM} with scrubber
Petroleum Coke Calciner	1. LoTOx^{TM} with scrubber 2. UltraCat
Portland Cement Kilns	1. SCR with or without scrubber 2. UltraCat 3. SNCR
Container Glass Melting Furnaces	1. SCR 2. UltraCat
Sodium Silicate Furnaces	3. SCR 4. UltraCat
Metal Heat Treating Furnaces	SCR
ICEs (Non-Refinery/Non-Power Plant)	1. SCR 2. NSCR
Non-Refinery/Non-Power Plant Gas Turbines	6. SCR 7. Flue Gas Recirculation 8. Staged Combustion/Low NOx Burners 9. Water/Steam Injection 10. Dry Low Emissions (DLE or DLN)

<u>Flue Gas Recirculation</u>

Flue Gas Recirculation (FGR) is a very common NOx reduction method used in boilers and process heaters that recycles a portion of low oxygen combustion by-products from the stack. These recirculated gases reduce the overall combustion temperature, which in turn, helps to reduce the formation of NOx. FGR can reduce thermal NOx emissions by as much as 70 percent or greater, depending on the method of introduction of the recirculated flue gases, the amount of FGR flow, and the type of fuel combusted. For example, when firing natural gas, typical NOx reductions are 45 percent with a 10 percent recirculation rate, and 75 percent with a 20 percent recirculation rate.

Staged Combustion & Low-NOx Burners

Staged combustion is another technique utilized in boilers, process heaters, metal melting furnaces, heat treating furnaces and other miscellaneous equipment to help achieve lower NOx emissions by dividing the combustion process into a number of stages in which the air-to-fuel ratio is varied to manipulate the conditions that would make NOx formation less ideal. Staged combustion is divided into two categories: staged air combustion and staged fuel combustion. Staged air combustion controls the formation of NOx by staging or staggering the total amount of air required for combustion to occur and can be achieved by installing low-NOx burners. Only a portion of the total air needed for combustion is used to form a fuel-rich primary combustion zone, in which all of the fuel is partially burned. Then, combustion is fully completed when the remainder of the combustion air is injected in a secondary zone which is located downstream of the fuel-rich primary zone. Because some heat is transferred prior to the completion of combustion, peak combustion temperatures are lower (which reduces formation of thermal NOx) with stage air combustion than with conventional combustion.

Without limiting the combustion air, staged fuel combustion controls the formation of NOx by staging the amount of fuel needed for combustion. With a high level of excess air in the primary combustion zone, the peak combustion temperature drops and subsequently reduces NOx formation. Additional fuel is later injected in the secondary combustion zone at a higher pressure and velocity than in the primary combustion zone, to stimulate FGR, further reduce combustion temperature, and decrease the availability of oxygen needed to form NOx.

Water/Steam Injection

The process of injecting water or steam into the flame in the combustion equipment reduces the flame temperature which lowers the formation of thermal NOx. Water/steam injection is typically used in conjunction with other NOx control methods such as FGR or burner modifications (e.g., low-NOx burners). Estimated reductions in NOx emissions from utilizing water/steam injection vary with the type of fuel combusted. For example, the use of water/steam injection and natural gas can achieve as much as 80 percent reduction in NOx.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is post-combustion control equipment that is considered to be BARCT, if cost-effective, for NOx control of existing combustion sources such as boilers, process heaters, and FCCUs as it is capable of reducing NOx emissions by as much as 95 percent or higher. A typical SCR system design consists of an ammonia storage tank, ammonia vaporization and injection equipment, a booster fan for the flue gas exhaust, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of ammonia and air directly into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor that is replete with catalyst, the catalyst, ammonia, and oxygen (from the air) in the flue gas exhaust reacts primarily (i.e., selectively) with NO and NO_2 to form nitrogen and water in the presence of a catalyst. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. There are two main types of catalysts: one in which the catalyst is coated onto a metal structure and a ceramic-based catalyst onto which the catalyst components are calcified. Commercial catalysts used in SCRs are available in two types of solid, block configurations or modules, plate or honeycomb type, and are comprised of a base material of titanium dioxide (TiO_2) that is coated with either tungsten trioxide (WO_3), molybdic anhydride (MoO_3), vanadium pentoxide (V_2O_5), iron oxide (Fe_2O_3), or zeolite catalysts. These catalysts are used for SCRs because of their high activity, insensitivity to sulfur in the exhaust, and useful life span of approximately five years or more. Ultimately, the material composition of the catalyst is dependent upon the application and flue gas conditions such as gas composition, temperature, et cetera.

For conventional SCRs, the minimum temperature for NOx reduction is 500 ^oF and the maximum operating temperature for the catalyst is 800 ^oF. Depending on the application, the type of fuel combusted, and the presence of sulfur compounds in the exhaust gas, the optimum flue gas temperature of an SCR system is case-by-case and will range between 550 ^oF and 750 ^oF to limit the occurrence of several undesirable side reactions at certain conditions. One of the major concerns with the SCR process is the poisoning of the catalyst due to the presence of sulfur and the oxidation of sulfur dioxide (SO_2) in the exhaust gas to sulfur trioxide (SO_3) and the subsequent reaction between SO_3 and ammonia to form ammonium bisulfate or ammonium sulfate. The formation of either ammonium bisulfate or ammonium sulfate depends on the amount of SO_3 and ammonia present in the flue gas and can cause equipment plugging downstream of the catalyst. The presence of particulates, heavy metals and silica in the flue gas exhaust can also limit catalyst performance. However, minimizing the quantity of injected ammonia and maintaining the ammonia temperature within a predetermined range will help avoid these undesirable reactions while minimizing the production of unreacted ammonia which is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip can vary between less than five ppmv when the catalyst is fresh and 20 ppmv at the end of the catalyst life.

In addition to the conventional SCR catalysts, there are high temperature SCR catalysts that can withstand temperatures up to 1200 ^oF and low temperature SCR catalysts that can operate below 500 ^oF.

<u>Non-Selective Catalytic Reduction</u>
Non-selective catalytic reduction (NSCR) is an add-on NOx control technology for high temperature exhaust streams with low O_2 content. NSCR uses a catalyst reaction to simultaneously convert NOx, CO, and VOC into water, CO_2, and nitrogen (N_2).

One type of NSCR system injects a reducing agent into the exhaust gas stream prior to the catalyst reactor to reduce the NOx. Another type of NSCR system has an afterburner and two catalytic reactors (one reduction catalyst and one oxidation catalyst). In this latter system, natural gas is injected into the afterburner to combust unburned hydrocarbons at a minimum temperature of 1,700 °F and the gas stream is cooled prior to entering the first catalytic reactor where CO and NOx are reduced. A second heat exchanger cools the gas stream to reduce the potential reformation of NOx before the second catalytic reactor where the remaining CO is converted to CO_2.

NSCR can achieve a NOx control efficiency ranging from 80 to 90 percent. The NOx reduction efficiency is dependent upon similar factors as for SCR, including the catalyst material and condition, the space velocity, and the catalyst bed operating temperature, air-to-fuel ratio, the exhaust gas temperature, and the presence of masking or poisoning agents. The operating temperatures for NSCR system range from approximately 700 °F to 1500 °F, depending on the catalyst. In order to achieve NOx reductions of 90 percent, the temperature must be between 800 °F and 1200 °F and the O_2 concentration must be less than four percent. To control NOx, CO, and VOC simultaneously, NSCR catalyst must operate in a narrow air-to-fuel ratio band (15.9-to-16.1 for natural gas-fired engines) that is close to stoichiometric. An electronic controller, which includes an oxygen sensor and feedback mechanism, is often necessary to maintain the air-to-fuel ratio in this narrow band. At this air-to-fuel ratio, the oxygen concentration in the exhaust is low, while concentrations of VOC and CO are not excessive.

<u>Selective Non-Catalytic Reduction</u>
Selective non-catalytic reduction (SNCR) is another post-combustion control technique typically used to reduce the quantity of NOx produced in the hot flue gas, by injecting ammonia. The main differences between SNCR and SCR is that the SNCR reaction between ammonia and NOx in the hot flue gas occurs without the need for a catalyst and at much higher temperatures (i.e., between 1200 ^{o}F to 2000 ^{o}F). The SNCR reaction is also affected by the short residence time of ammonia and the molecular ratio between ammonia and the initial quantities of NOx such that small quantities of unreacted ammonia remains (i.e., as ammonia slip) and is subsequently released in the flue gas. With a control efficiency ranging between 80 and 85 percent, SNCR does not achieve as great of NOx emission reductions as SCR. The need for the exhaust temperature to be high limits the applicability of SNCR to boilers, cement kilns, and in some cases, FCCUs. Therefore, the use of SNCR alone would not be considered equivalent to BARCT.

<u>Wet Gas Scrubbers (WGSs)</u>
WGS technology is a multi-pollutant control system that primarily controls SOx and PM emissions but can be installed to function with NOx control equipment. WGSs can be used to control emissions from FCCUs, refinery process heaters and boilers, SRU/TGUs, petroleum coke calciners, and cement kilns. There are two types of wet gas scrubbers: 1) caustic-based non-regenerative WGS; and, 2) regenerative WGS.

In non-regenerative wet gas scrubbing, caustic soda (sodium hydroxide - NaOH) or other alkaline reagents, such as soda ash, are used as an alkaline absorbing reagent (absorbent) to capture SO_2 emissions. The absorbent captures SO_2 and sulfuric acid mist (H_2SO4) and converts it to various types of sulfites and sulfates (e.g., $NaHSO_3$, Na_2SO_3, and Na_2SO_4). The absorbed sulfites and sulfates are later separated by a purge treatment system and the treated water, free of suspended solids, is either discharged or recycled.

One example of the caustic-based non-regenerative scrubbing system is the proprietary Electro Dynamic Venturi (EDV) scrubbing system offered by BELCO Technologies Corporation (see Figure 1-6). An EDV scrubbing system consists of three main modules: 1) a spray tower module; 2) a filtering module; and, 3) a droplet separator module. The flue gas enters the spray tower module, which is an open tower with multiple layers of spray nozzles. The nozzles supply a high density stream of caustic/water solution that is directed in a countercurrent flow to the gas flow and encircles, encompasses, wets, and saturates the flue gas. Multiple stages of liquid/gas absorption occur in the spray tower module and SO_2 and acid mist are captured and converted to sulfites and sulfates. Large particles in the flue gas are also removed by impaction with the water droplets.

The flue gas saturated with heavy water droplets continues to move up the wet scrubber to the filtering module where the flue gas reaches super-saturation. At this point, water continues to condense and the fine particles in the gas stream begin to cluster together, to form larger and heavier groups of particles. Next, the flue gas, super-saturated with heavy water droplets, enters the droplet separator module causing the water droplets to impinge on the walls of parallel spin vanes and drain to the bottom of the scrubber.

The spent caustic/water solution purged from the WGS is later processed in a purge treatment unit. The purge treatment unit contains a clarifier that removes suspended solids for disposal. The effluent from the clarifier is oxidized with agitated air to help convert sulfites to sulfates and also reduce the chemical oxygen demand (COD) so that the effluent can be safely discharged to a wastewater system.

A regenerative WGS removes SO_2 from the flue gas by using a buffer solution that can be regenerated. The buffer is then sent to a regenerative plant where the SO_2 is extracted as concentrated SO_2. The concentrated SO_2 is then sent to a sulfur recovery unit (SRU) to recover the liquid SO_2, sulfuric acid and elemental sulfur as a by-product. When the inlet SO_2 concentrations are high, a substantial amount of sulfur-based by-products can be recovered and later sold as a commodity for use in the fertilizer, chemical, pulp and paper industries. For this reason, the use of a regenerative WGS is favored over a non-regenerative WGS.

One example of a regenerative scrubber is the proprietary LABSORB offered by BELCO Technologies Corporation [6, 7]. The LABSORB scrubbing process uses a patented non-organic aqueous solution of sodium phosphate salts as a buffer. This buffer is made from two common available products, caustic and phosphoric acid. The LABSORB system consists of: 1) a quench pre-scrubber; 2) an absorber; and, 3) a regeneration section which typically includes a stripper and a heat exchanger.

In the scrubbing side of the regenerative scrubbing system, the quench pre-scrubber is used to wash out any large particles that are carried over, plus any acid components in the flue gas such as hydrofluoric acid (HF), hydrochloric acid (HCl), and SO_3. The absorption of SO_2 is carried out in the absorber. The absorber typically consists of one single, high-efficiency packed bed scrubber filled with high-efficiency structural packing material. However, if the inlet SO_2 concentration is low, a multiple-staged packed bed scrubber, or a spray-and-plate tower scrubber, may be used instead to achieve an ultra-low outlet SO_2 concentration.

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[6] *Evaluating Wet Scrubbers*, Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

[7] *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005.

The third step in the regenerative wet gas scrubbing system is the regenerative section in which the SO_2-rich buffer stream is steam heated to evaporate the water from the buffer. The buffer stream is then sent to a stripper/condenser unit to separate the SO_2 from the buffer. The buffer free of SO_2 is returned to the buffer mixing tank while the condensed-SO_2 gas stream is sent back to the SRU for further treatment.

LoTOx™ Application with Scrubber

The LoTOx™ is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. LoTOx™ stands for "Low Temperature Oxidation" process in which ozone (O_3) is used to oxidize insoluble NOx compounds into soluble NOx compounds which can then be removed by absorption in a caustic, lime or limestone solution. The LoTOx™ process is a low temperature application, optimally operating at about 325 ^{o}F.

A typical combustion process produces about 95 percent NO and five percent NO_2. Because both NO and NO_2 are relatively insoluble in an aqueous solution, a WGS alone is not efficient in removing these insoluble compounds from the flue gas stream. However, with a LoTOx™ system and the introduction of O_3, NO and NO_2 can be easily oxidized into a highly soluble compound N_2O_5 (see Reactions 5 and 6) and subsequently converted to nitric acid (HNO_3) (see Reaction 7). Then, in a wet gas scrubber for example, the HNO_3 is rapidly absorbed in caustic (NaOH) (see Reaction 8), limestone or lime solution (see Reactions 9 and 10). In addition, because the rates of oxidizing reactions for NOx (see Reactions 5 and 6) are fast compared to the very slow SO_2 oxidation reaction (see Reaction 11), no ammonium bisulfate ($(NH_4)HSO_4$) or sulfur trioxide (SO_3) is formed.

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 - Fast)
$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$	(Reaction 7)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 - Very slow)

The LoTOx™ process requires a source of oxygen and generates O_3 on site. Typically oxygen (O_2) is stored as a liquid in vacuum-jacketed vessels or is delivered by pipeline. O_3 is an unstable gas and it is typically generated on demand from the O_2 supply using an O_3 generator. An O_3 generator is shaped similar to a shell and tube heat exchanger and uses a corona discharge to dissociate the O_2 molecules into individual atoms so that the individual oxygen atoms combine with each other to form O_3. The LoTOx™ process contains an ozone injection manifold designed to achieve uniform distribution and complete mixing. A ratio of 1.75 parts NOx to 2.5 parts O_3 is needed in order to achieve a NOx conversion and reduction of 90 percent to 95 percent. Since sulfur dioxiode (SO_2) is an ozone scavenger because it readily bonds with O_3 to form sulfur trioxide (SO_3), the LoTOx™ process typically has a very low O_3 slip (excess O_3) that ranges from zero ppmv to three ppmv. Figure 1-5 shows a schematic of the O_3 generation process.

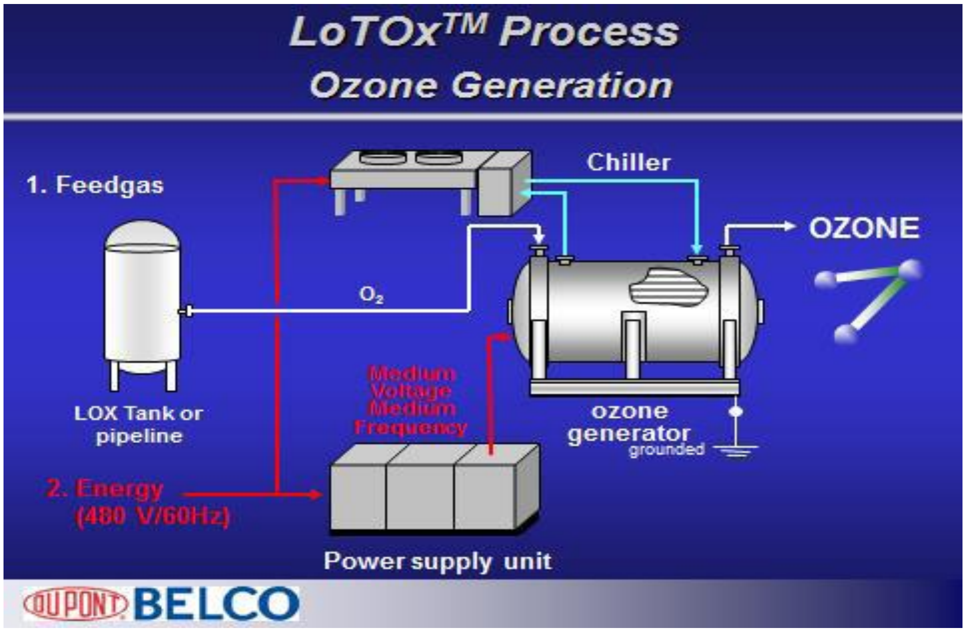

Figure 1-5: Ozone Generation Process

The LoTOx™ process can be integrated with any type of wet scrubbers (e.g., venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs). For example, Linde has engineered more than 24 LoTOx™ applications for EDV™ scrubbers engineered by BELCO since 2007 for refinery FCCU applications. A LoTOx™ system with an EDV™ scrubber is shown in Figure 1-6.

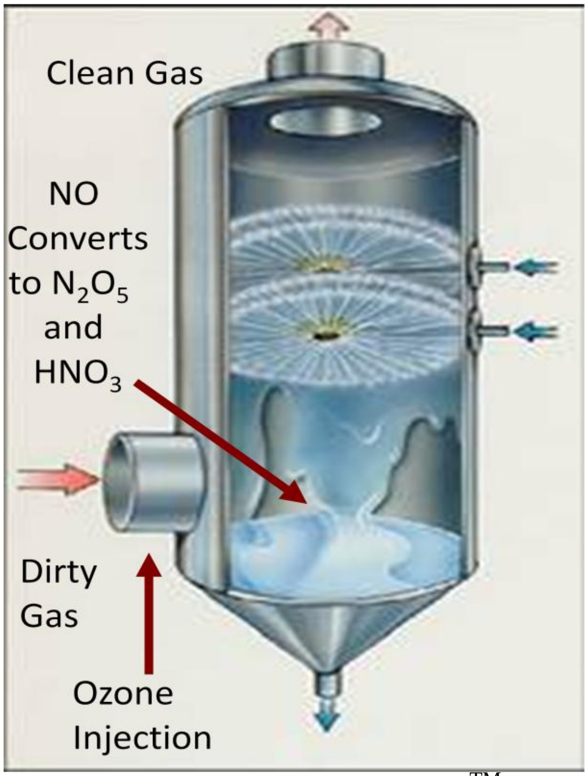

Figure 1-6: EDV Scrubber with LoTOx™ Application

In addition, MECS, BELCO's sister company, has engineered more than two dozen DynaWave scrubbers with LoTOx™ systems specifically designed for refinery SRU/TGUs. Figure 1-7 shows a schematic for a DynaWave scrubber with a LoTOx™ application.

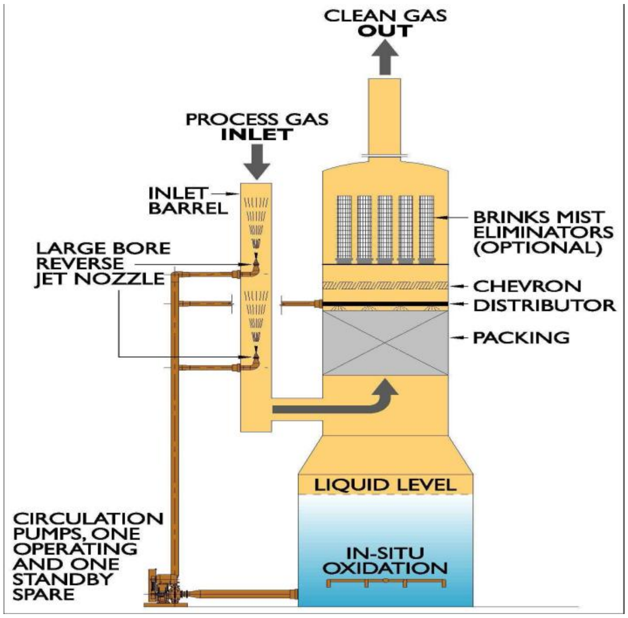

Figure 1-7: DynaWave Scrubber with LoTOx™ Application

When compared to SCR technology, the LoTOx™ application has several advantages, as follows:

- Unlike SCR which operates at high temperatures, LoTOx™ is a low temperature operating system that does not require additional heat input to maintain operational efficiency and enable maximum heat recovery of high temperature combustion gases.
- Unlike SCR which is primarily designed to reduce only NOx, LoTOx™ can be integrally connected to a scrubber (e.g., wet or semi-dry scrubber, or wet electrostatic ESP) and become a multi-component air pollution control system capable of reducing NOx, SOx and PM in one system.
- There is no formation of ammonia slip, SO_3, or $(NH_4)HSO_4$ with the LoTOx™ process.

<u>KnowNOx™ Application with Scrubber</u>
In lieu of using O_3 to convert NO and NO_2 to N_2O_5 and HNO_3, the KnowNOx™ technology uses chlorine dioxide ClO_2. The manufacturer of KnowNOx™ claims that the conversion reactions (see Reactions 12 and 13) are in the gas phase, which can occur much faster than the liquid phase reactions with O_3 (see Reactions 5 through 8 in the previous LoTOx™ Application discussion).

$5\ NO + 2\ ClO_2 + H_2O \rightarrow 5\ NO_2 + 2\ HCl$ (Reaction 12 - Gas Phase)

$5\ NO_2 + ClO_2 + 3\ H_2O \rightarrow 5\ HNO_3 + 2\ HCl$ (Reaction 13 – Gas Phase)

$5\ SO_2 + 2\ ClO_2 + 6\ H_2O \rightarrow 5\ H_2SO_4 + 2\ HCl$ (Reaction 10)

With the KnowNOx^{TM} technology, it takes less than 0.5 seconds to achieve 99.8 percent or more conversion. The reactions require a smaller vessel relative to the size needed for the LoTOx^{TM} reaction chamber. In addition, the KnowNOx^{TM} process can simultaneously reduce NOx, SO_2, PM and other contaminants.

The KnowNOx^{TM} process includes a three-staged scrubbing system: 1) SO_2 is removed via a DynaWave scrubber; 2) then ClO_2 is injected into the scrubber exhaust stream where the NO and NO_2 are converted into HNO_3 and other soluble salts; and, 3) any H_2S that is generated during the second stage is converted to soluble salts. To date, the KnowNOx^{TM} technology has been installed at two locations in the U.S. but has not yet been tested in any refinery applications. Figure 1-8 shows a schematic of a scrubber with KnowNOx^{TM}.

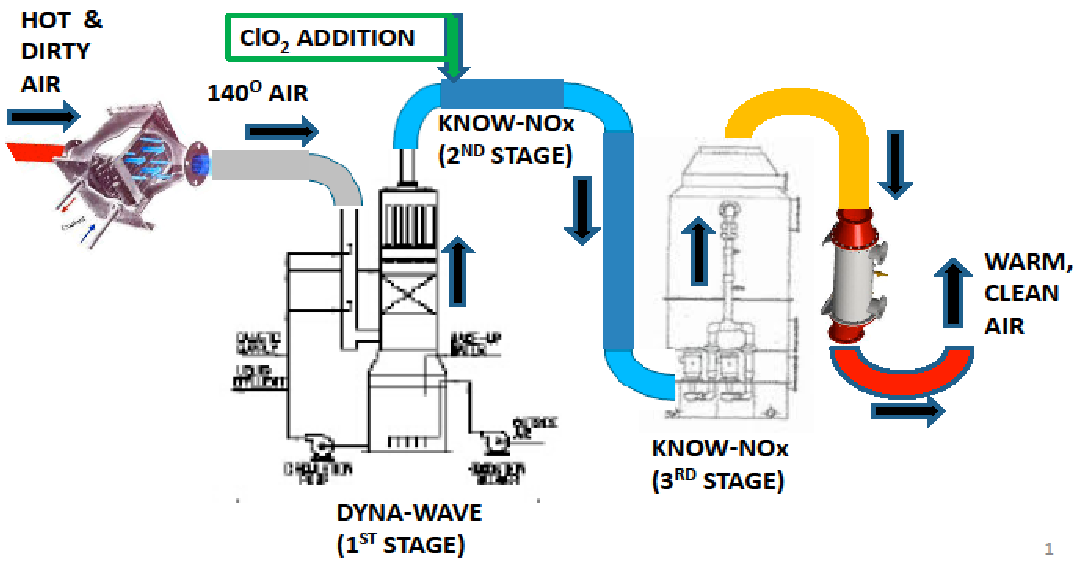

Figure 1-8: Scrubber with KnowNOx^{TM} Application

<u>NOx Reducing Additives</u>

Combustion in a FCCU regenerator generates various pollutants (e.g., NO, N_2O, NO_2, HCN, NH_3, SO_2, etc.) and their dynamic interaction with each other is complex. "Fuel" nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, and NO_2. The rates of these reactions depend heavily on the FCCU regenerator temperatures and configuration. NOx reducing additives can be used to promote the conversion of NOx, HCN, and NH_3 to elemental nitrogen (N_2) and reduce NOx emissions. The removal efficiency for NOx reducing additives can range between 50 percent and 80 percent. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure 1-9.

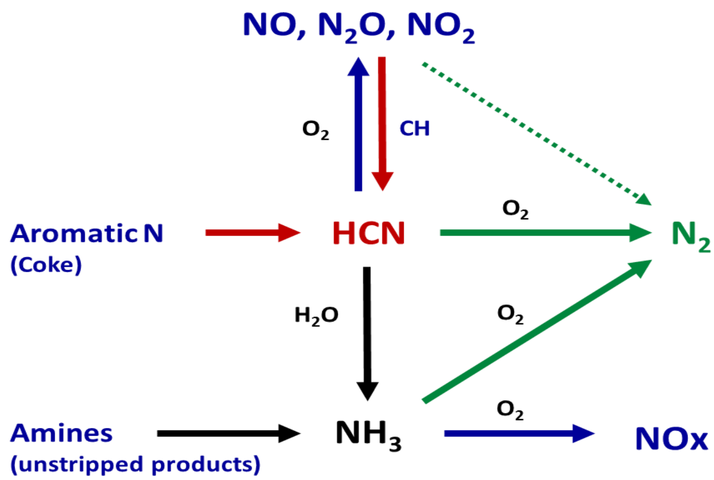

Figure 1-9: Nitrogen Chemistry in the FCCU Regenerator

When using NOx reducing additives, manufacturers recommend the following best practices to minimize the formation of NOx and simultaneously promote the conversion of CO to CO_2: 1) minimize excess oxygen since higher amounts of excess oxygen favors the undesirable formation of NOx rather than N_2; 2) reduce nitrogen in the feed stream; and, 3) utilize non-platinum CO promoters.

Ammonia Slip Catalyst (ASC) and CO Catalyst

SCR manufacturers have developed Ammonia Slip Catalyst (ASC) which is a layer of catalyst that is installed downstream of the SCR catalyst to enhance the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The use of ASCs allow for operations at higher NH_3/NOx ratios to ensure complete NOx conversion while maintaining low ammonia slip.

Similar to ASC, CO catalyst is used in conjunction with the SCR catalyst to concurrently reduce NOx to N2 and oxidize CO and hydrocarbon to CO2 and water. CO catalyst is typically made of platinum, palladium or rhodium, and is capable of removing approximately 90 percent of CO and 85 percent to 90 percent of hydrocarbon or hazardous air pollutants from an exhaust stream.

Great Southern Flameless Heaters

In 2012, Coffeyville Resources purchased the world's first flameless crude heater designed by Great Southern Flameless for their Coffeyville refinery in Kansas to comply with a Consent Decree issued by the U.S. EPA. The flameless heater has been in operation for over one year and has proven an achieved-in-practice performance of five ppmv NOx at three percent O_2 with pilot lights in operation, and three ppmv NOx without pilot lights for flameless technology.

Great Southern can supply flameless heaters or oxy-fuel flameless heaters with maximum rating from 10 mmBTU/hr to 320 mmBTU/hr (e.g., equivalent to 240 mmBTU/hr process duty.) Their production capacity is 30 heaters per year. The modules are designed and fabricated in Oklahoma and then they are shipped in pieces to the field where they are assembled at the site. The heaters can use the same foundation of the conventional heaters. From cold start, the heater is brought up in natural draft mode in the same manner as any typical conventional heater. The firing rate of the heater is gradually increased to the required level while the combustion air is gradually increased to 850 ^oF. Once the combustion air temperature exceeds 850 ^oF, it will sustain the automatic ignition of fuel, and the heater is transitioned into the staged fuel firing mode with pilots off-line. The heater is operated in the staged firing mode until steady state operation is achieved. At this point, the heater is transitioned into flameless firing mode. Visible flame from the conventional nozzles disappears and the NOx emissions decrease substantially in the flameless mode operation. The heater can also be designed for combustion with oxygen.

According to Great Southern Flameless, flameless heaters can be designed to achieve: 1) five ppmv NOx at three percent O_2; or, 2) two ppmv NOx at three percent O_2 with the pilot lights off during flameless firing and with a fuel mix of 25 percent natural gas and 75 percent refinery gas. In addition, oxy-fuel flameless heaters can be designed to achieve: 1) two ppmv NOx at three percent O_2; or, 2) one ppmv with the pilot lights off during flameless firing.

<u>UltraCat</u>

UltraCat is a commercially available multi-pollutant control technology designed to remove NOx and other pollutants such as SO_2, PM, HCl, Dioxins, and HAPs such as mercury in low temperature applications. UltraCat technology is comprised of filter tubes which are made of fibrous ceramic materials embedded with proprietary catalysts. The optimal operating temperature range of an UltraCat system is approximately 350 ^oF to 750 ^oF. In order to achieve a NOx removal efficiency of approximately 95 percent, aqueous ammonia is injected upstream of the UltraCat filters. In addition, to remove SO_2, HCl, and other acid gases with a removal efficiency ranging from 90 percent to 98 percent, dry sorbent such as hydrated lime, sodium bicarbonate or trona is also injected upstream of the UltraCat filters. UltraCat is also capable of controlling particulates to a level of 0.001 grains per standard cubic foot of dry gas (dscf).

The UltraCat filters are arranged in a baghouse configuration with a low pressure drop such as five inches water column (inH20) across the system. The UltraCat system is equipped with a reverse pulse-jet cleaning action that back flushes the filters with air and inert gas to dislodge the PM deposited on the outside of the filter tubes. Depending on the loading, catalytic filter tubes need to be replaced every five to 10 years. The UltraCat system is shown in Figure 1-10.

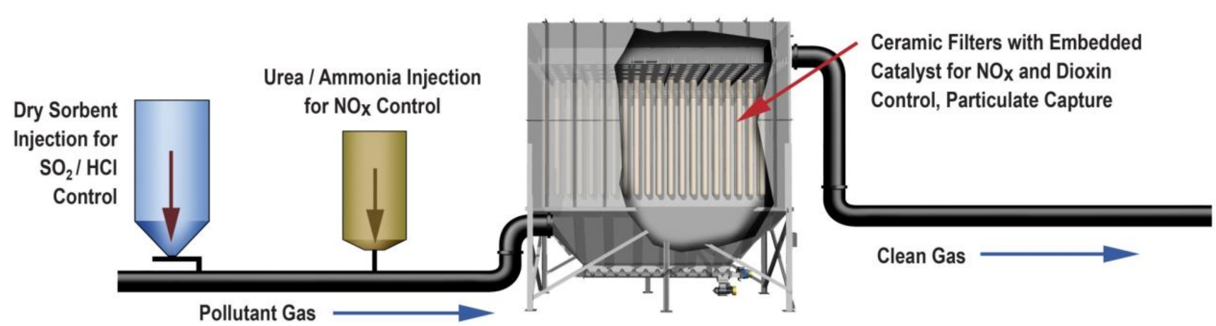

Figure 1-10: UltraCat System

<u>ClearSign Technology</u>

The ClearSign Combustion Corporation in Seattle has developed two technologies applicable for boilers and heaters: 1) DUPLEX™ technology; and, 2) Electrodynamic Combustion Control (ECC™). These technologies are expected to generate very low NOx and CO emissions without the need for FGR, SCR, or large quantities of excess air.

DUPLEX™ technology can be installed in new boilers or heaters. Also, existing boilers and heaters can be retrofit with DUPLEX™ technology. The DUPLEX™ technology comprises a proprietary DUPLEX™ tile installed downstream of the conventional burners. The hot combustion flame from the conventional burners impinges onto the DUPLEX™ tile, and the tile helps evenly radiate the heat with a high emissivity to the combustion products. The DUPLEX™ operation also creates more mixing and shorter flames. Since the flame length is one parameter that limits the total heat release in a furnace, decreased flame length can allow for significantly higher process throughputs. The DUPLEX™ tile is expected to have a three- to five-year lifespan.

The ECC™ technology uses an electric field to effectively shape the flame, accelerate flame speed, and improve flame stability. The total electrical field power required to generate such effects is less than 0.1 percent of the firing rate. Emission performance from a bench test has been demonstrated for both DUPLEX™ and ECC™ and the NOx and CO emissions were both demonstrated to be less than five ppmv as long as the furnace temperatures were steadily maintained between 1200 ^{o}F and 1800 ^{o}F. Beside the benefits of reducing air pollution, ClearSign believes that their burners will provide substantial economic benefits from more uniform heat distribution, improved process throughput, and potentially reduced maintenance costs.

Cheng Low NOx

Cheng Low NOx burner technology applies steam injection to the inlet fuel for combustion in the gas turbine. This is different than traditional steam injection which involves the injection of the steam to the compressed combustion air before entering the combustion chamber. The burner retrofits involve the installation of a new set of nozzles that can deliver a uniform, homogenous mix of steam and fuel to the combustion chamber, and in turn, will reduce NOx formation. Steam injection also provides an added boost to the gas turbine's output power due to the increased mass flow rate. The heat recovery steam generator (HRSG) typically will produce the process steam for the system. The NOx emission level that can be achieved by utilizing Cheng Low NOx burner technology is typically under five ppm and can go as low as two ppm with a 3:1 or 4:1 steam-to-fuel ratio.

Dry Low NOx (DLN) or Dry Low Emissions (DLE)

Staged combustion is identified through a variety of names, including Dry Low NOx (DLN) and Dry Low Emissions (DLE), and is a type of dry control which involves a major modification to a turbine's combustion system. The majority of gas turbines manufactured today are lean-premix dual-staged combustion turbines. Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower flame temperatures and higher concentrations of CO and H_2, because of incomplete combustion, while decreasing the amount of oxygen available for the formation of NOx. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. Thus, by staging DLE combustors so that the air and fuel is pre-mixed and combusting the mixture to produce a lower flame temperature, lower NOx emissions (e.g., in the range between three ppm and 25 ppm for gaseous fuel and 10 ppm for liquid fuel) are created as a by-product.

ALTERNATIVES

The Draft PEA will discuss and compare a range of reasonable alternatives to the proposed project as required by CEQA Guidelines §15126.6 and by SCAQMD Rule 110 where there are potential significant adverse environmental impacts. Alternatives must include realistic measures for attaining the basic objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. In addition, the range of alternatives must be sufficient to permit a reasoned choice and it need not include every conceivable project alternative. The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative.

SCAQMD Rule 110 does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an Environmental Impact Report under CEQA. Alternatives will be developed based in part on the major components of the proposed project. The rationale for selecting alternatives rests on CEQA's requirement to present "realistic" alternatives; that is alternatives that can actually be implemented. CEQA also requires an evaluation of a "No Project Alternative."

SCAQMD’s policy document Environmental Justice Program Enhancements for fiscal year (FY) 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA environmental assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a “least harmful” perspective with regard to hazardous air emissions.

The Governing Board may choose to adopt any portion or all of any alternative presented in the PEA with appropriate findings as required by CEQA. The Governing Board is able to adopt any portion or all of any of the alternatives presented because the impacts of each alternative will be fully disclosed to the public and the public will have the opportunity to comment on the alternatives and impacts generated by each alternative. Written suggestions on potential project alternatives received during the comment period for the Initial Study will be considered when preparing the Draft PEA.

CHAPTER 2

ENVIRONMENTAL CHECKLIST

Introduction

General Information

Potentially Significant Impact Areas

Determination

Environmental Checklist and Discussion

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by adopting the proposed amendments to Regulation XX.

GENERAL INFORMATION

Project Title:	Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive, Diamond Bar, CA 91765
CEQA Contact Person:	Barbara Radlein, (909) 396-2716
Regulation XX Contact Person:	Minh Pham, (909) 396-2613
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive, Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	SCAQMD staff is proposing amendments to Regulation XX – RECLAIM, Rule 2002 – Allocations for NOx and SOx, to reduce the allowable NOx emission limits based on current BARCT to achieve additional NOx emission reductions for the following industrial equipment and processes: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RTCs and NOx RTC adjustment factors for year 2016 and later. For clarity and consistency throughout the regulation, other minor changes are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping SOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures); and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping NOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures). The Initial Study identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Impacts to these environmental areas will be further analyzed in the Draft PEA.
Surrounding Land Uses and Setting:	Industrial, commercial, and residential
Other Public Agencies Whose Approval is Required:	Not applicable

POTENTIALLY SIGNIFICANT IMPACT AREAS

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. Any checked items represent areas that may be adversely affected by the proposed project. An explanation relative to the determination of impacts can be found following the checklist for each area.

☑	Aesthetics	☐	Geology and Soils	☐	Population and Housing
☐	Agriculture and Forest Resources	☑	Hazards and Hazardous Materials	☐	Public Services
☑	Air Quality and Greenhouse Gas Emissions	☑	Hydrology and Water Quality	☐	Recreation
☐	Biological Resources	☐	Land Use and Planning	☑	Solid and Hazardous Waste
☐	Cultural Resources	☐	Mineral Resources	☑	Transportation and Traffic
☑	Energy	☐	Noise	☑	Mandatory Findings of Significance

DETERMINATION
On the basis of this initial evaluation:

☐ I find the proposed project, in accordance with those findings made pursuant to CEQA Guideline §15252, COULD NOT have a significant effect on the environment, and that an ENVIRONMENTAL ASSESSMENT with no significant impacts has been prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. An ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☑ I find that the proposed project MAY have a significant effect(s) on the environment, and an ENVIRONMENTAL ASSESSMENT will be prepared.

☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: December 4, 2014 **Signature:** Michael Krause

Michael Krause
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

ENVIRONMENTAL CHECKLIST AND DISCUSSION

Since NOx is a precursor pollutant to fine particulate matter (PM10 and PM2.5) and ozone, SCAQMD staff is proposing amendments to Regulation XX – RECLAIM, to achieve additional NOx emission reductions as outlined in the Final 2012 AQMP. Specifically, amendments are proposed to Rule 2002 – Allocations for NOx and SOx to address BARCT requirements, which may require installation or modification of NOx emission control equipment or techniques. For clarity and consistency throughout the regulation, other minor changes that are administrative in nature and include minor clarifications are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping SOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures); and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping NOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures).

The amendments proposed in Rule 2002 for the overall reductions in NOx RTC allocations, which include the anticipated feasible NOx emissions reductions due to compliance with proposed BARCT requirements, are expected to involve physical changes at affected facilities which may cause potentially significant impacts to the following environmental topics: aesthetics; air quality and GHG emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Therefore, the type of emission reduction projects that may be undertaken to comply with the proposed project, primarily the reduced total amounts of NOx credits available in the RECLAIM program, are the main focus of the analysis in this Initial Study.

Preliminary review of the SCAQMD's RECLAIM database indicates that certain equipment at the top emitting NOx RECLAIM facilities are currently not operating at proposed BARCT levels. This analysis assumes that operators at RECLAIM facilities will elect to reduce emissions at their facilities through further control of emissions from equipment not operating at BARCT rather than purchasing NOx RTCs, as is currently allowed under the RECLAIM program. The rationale for this assumption is that controlling emissions from equipment not operating at BARCT will produce the most conservative analysis of secondary adverse environmental impacts. The physical changes involved with the type of emission control strategies that are expected to occur focus on the installation of new or the modification of existing NOx emission control equipment for the following industrial equipment and processes: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. To control NOx emissions from these sources, an assortment of technologies may be applied individually or in combination to meet proposed BARCT, depending on the source category, as follows (in alphabetical order): Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx™ with scrubber; LoTOx™ with scrubber; NOx reducing additives; NSCR; SCR with or without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection. For the purpose of the CEQA analysis, the selection of certain control technology is based on the potential to cause secondary adverse environmental impacts in order to render the analysis conservative regardless of costs. It is important to note that the rule development process, including the proposed BARCT determination and RTC shave methodology, are ongoing and as such may be revised based on input from stakeholders and the public. As additional information becomes available, the project will be updated and any additional environmental impacts will be evaluated in the Draft PEA.

It must be also noted that the projects assumed to occur as a means of reducing NOx emissions in response to the proposed amendments could occur voluntarily under the existing RECLAIM program. In addition, as with the current regulation or with the proposed project, affected facilities may purchase NOx RTCs instead of implementing physical changes to achieve a reduction in NOx emissions. However, the proposed amendments to the RECLAIM program would further induce such control strategies to occur as facility allocations are being reduced.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
I.	**AESTHETICS.** Would the project:				
a)	Have a substantial adverse effect on a scenic vista?	☐	☐	☐	☑
b)	Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☐	☑
c)	Substantially degrade the existing visual character or quality of the site and its surroundings?	☑	☐	☐	☐
d)	Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☑	☐

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Discussion

I. a) & b) No Impact. Depending on how the affected facilities choose to comply with the proposed NOx reductions, implementation of the proposed project could involve construction activities related to the modification of existing equipment at the top NOx emitting RECLAIM facilities.

The physical changes involved with the type of NOx emission control strategies that are expected focus on the installation of new or the modification of existing control equipment at the following stationary sources of NOx: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. To control NOx emissions from these sources, an assortment of technologies may be applied individually or in combination to meet proposed BARCT, depending on the source category, as follows (in alphabetical order): Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx™; LoTOx™ with scrubber; NOx reducing additives; NSCR; SCR with or without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection.

Construction activities are expected as part of the proposed project. However, the construction activities would be temporary and would not be expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities would be expected to occur within the confines of each existing facility and would be expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility. Except for the potential use of cranes, the majority of the construction equipment is expected to be low in height and not substantially visible to the surrounding area due to existing fencing along the property lines and existing structures currently within the facilities that would buffer the views of the construction activities. Further, the construction activities are expected to be temporary in nature and will cease following completion of the equipment installation or modifications.

Depending on the type of NOx emissions control employed, the proposed project could potentially introduce minor visual changes at some facilities. The affected units, depending upon their locations within each facility, could potentially be visible to areas outside of each facility. However, the affected units are expected to be about the same size profile relative to the existing equipment or structures present at each affected facility. The general appearance of the affected units is not expected to differ significantly from other equipment units such that no significant impacts to aesthetics are expected. Further, no scenic highways or corridors are located in the vicinities of the affected facilities such that the proposed project would not obstruct scenic resources or degrade the existing visual character of a site, including but not limited to, trees, rock outcroppings, or historic buildings. Accordingly, these impact issues will not be further analyzed in the Draft PEA. Further, since no significant aesthetics impacts were identified for these issues, no mitigation measures are necessary or required.

I. c) Potentially Significant Impact. All construction and operational activities associated with the proposed project are expected to take place within the boundaries of the existing RECLAIM facilities. As explained in 1. a) and b), during construction, cranes may be needed during construction and they may be visible to the surrounding areas. However, except for the use of cranes, the majority of construction equipment that will be used to comply with the proposed project will be low in height and will not be visible to the surrounding areas due to the presence of existing fences and other structures that buffer views. Since the construction activities are temporary in nature, all construction equipment will be removed following completion of the proposed project.

Of the new equipment that may be installed, or the existing equipment that may be modified as part of the proposed project, all of the control technologies except for WGSs will be similar in size, appearance, and profile to the existing equipment and surrounding structures. Thus, no operational aesthetics impacts from the installation or application of the following technologies would be expected to substantially degrade the existing visual character or quality of the site and its surroundings: Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx™; NOx reducing additives; NSCR; SCR without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection.

However, wet gas scrubber (WGS) technology in combination with LoTOx™ or an SCR is potentially BARCT for five FCCUs, six SRU/TGUs, multiple refinery process heaters and boilers, a petroleum coke calciner, and Portland cement kilns. If a WGS scrubber is installed for any of these source categories, upon completion of construction, the operation of the WGS will emit flue gas that is saturated with water that, depending on weather conditions, could form a visible steam plume. Depending on the size of the WGS installed, the flue gas stack could be as tall as 200 feet above grade. For this reason, each WGS, its stack, and subsequent steam plume may have the potential to generate significant aesthetic impacts. Therefore, these potential impacts to aesthetics will be addressed in the Draft PEA for the proposed project.

I. d) Less Than Significant Impact. There are no components in the proposed project that would require construction activities to occur at night. Therefore, no additional lighting at the affected facilities would be required as a result of complying with the proposed project. However, if facility operators determine that the construction schedule requires nighttime activities, temporary lighting may be required. Nonetheless, since construction of the proposed project would be completely located within the boundaries of each affected facility, additional temporary lighting is not expected to be discernable from the existing permanent night lighting.

Some facilities, such as refineries for example, operate 24 hours per day, so lighting is already part of the existing setting. However, additional permanent light sources may be installed on any installation of new equipment, to provide illumination for operations personnel at night, in accordance with applicable safety standards. Similarly, any existing equipment that would be modified as part of the proposed project are located in existing structures or areas that already have lighting systems in place for the same reasons. These additional light sources are not expected to create an impact because each component of the proposed project will be located within an existing industrial facility that operates up to 24 hours per day and the equipment is not restricted to operate during a specific time of day. The proposed project contains no provisions that would require affected equipment to operate differently during existing daytime or nighttime operations. Further, any new lighting that will be installed on the proposed equipment will be consistent in intensity and type with the existing lighting on equipment and other structures within each affected facility. While residential areas are located near some of the affected facilities, any additional lighting will be placed by and focused on the new equipment. For the aforementioned reasons, the proposed project is not expected to create a new source of substantial light or glare that would adversely affect day or nighttime views in the area. Therefore, less than significant impacts to light and glare are expected from the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant aesthetics impacts were identified for this issue, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to aesthetics may occur from implementing the proposed project and thus, impact issue I. c) will be further analyzed in the Draft PEA.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
II.	**AGRICULTURE AND FOREST RESOURCES.** Would the project:				
a)	Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland mapping and Monitoring Program of the California Resources Agency, to non- agricultural use?	☐	☐	☐	☑
b)	Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☐	☑
c)	Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined by Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104 (g))?	☐	☐	☐	☑
d)	Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on agriculture and forest resources will be considered significant if any of the following conditions are met:

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.

- The proposed project conflicts with existing zoning for, or causes rezoning of, forest land (as defined in Public Resources Code §12220 (g)), timberland (as defined in Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code § 51104 (g)).
- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of farmland to non-agricultural use or conversion of forest land to non-forest use.

Discussion

II. a), b), c), & d) No Impact. Land use, including agriculture- and forest-related uses, and other planning considerations are determined by local governments. While implementation of the proposed project may cause air pollution control equipment to be installed and operated on existing equipment to control NOx emissions, these activities will occur at established NOx RECLAIM facilities which are located on previously developed land in primarily industrial areas and are not located in the vicinity of agricultural or forest areas.

Further, no new construction of buildings or other structures is expected that would require conversion of farmland to non-agricultural use or conflict with zoning for agricultural uses or a Williamson Act contract. Further, because the proposed project does not require construction or operation activities within an area designated as forest land, implementation of the proposed project is not expected to conflict with any forest land zoning codes or convert forest land to non-forest uses. Similarly, there is nothing in the proposed project that would affect or conflict with existing land use plans, policies, or regulations or require conversion of farmland to non-agricultural uses or forest land to non-forest uses. Thus, no agricultural land use or planning requirements will be altered by the proposed project.

Finally, in the event the proposed project is implemented, the installation of NOx control equipment will ensure that projected NOx emission reductions will occur and that air quality in the region will improve. Thus, assuring that these air quality improvements occur could provide benefits to agricultural and forest land resources by reducing the adverse oxidation impacts of ozone on plants and animals located in the Basin. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant agricultural and forest resources impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant agriculture and forest resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant With Mitigation**	**Less Than Significant Impact**	**No Impact**
III. AIR QUALITY AND GREENHOUSE GAS EMISSIONS. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☐	☑
b) Violate any air quality standard or contribute to an existing or projected air quality violation?	☑	☐	☐	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors)?	☑	☐	☐	☐
d) Expose sensitive receptors to substantial pollutant concentrations?	☑	☐	☐	☐
e) Create objectionable odors affecting a substantial number of people?	☑	☐	☐	☐
f) Diminish an existing air quality rule or future compliance requirement resulting in a significant increase in air pollutant(s)?	☐	☐	☐	☑
g) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☑	☐	☐	☐
h) Conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☑	☐

Significance Criteria

To determine whether or not air quality and GHG impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the criteria in Table 2-1. The project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 2-1 are equaled or exceeded.

Table 2-1
SCAQMD Air Quality Significance Thresholds

<table>
<tr><th colspan="3">Mass Daily Thresholds [a]</th></tr>
<tr><th>Pollutant</th><th>Construction [b]</th><th>Operation [c]</th></tr>
<tr><td>NOx</td><td>100 lbs/day</td><td>55 lbs/day</td></tr>
<tr><td>VOC</td><td>75 lbs/day</td><td>55 lbs/day</td></tr>
<tr><td>PM10</td><td>150 lbs/day</td><td>150 lbs/day</td></tr>
<tr><td>PM2.5</td><td>55 lbs/day</td><td>55 lbs/day</td></tr>
<tr><td>SOx</td><td>150 lbs/day</td><td>150 lbs/day</td></tr>
<tr><td>CO</td><td>550 lbs/day</td><td>550 lbs/day</td></tr>
<tr><td>Lead</td><td>3 lbs/day</td><td>3 lbs/day</td></tr>
<tr><th colspan="3">Toxic Air Contaminants (TACs), Odor, and GHG Thresholds</th></tr>
<tr><td>TACs
(including carcinogens and non-carcinogens)</td><td colspan="2">Maximum Incremental Cancer Risk ≥ 10 in 1 million
Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million)
Chronic & Acute Hazard Index ≥ 1.0 (project increment)</td></tr>
<tr><td>Odor</td><td colspan="2">Project creates an odor nuisance pursuant to SCAQMD Rule 402</td></tr>
<tr><td>GHG</td><td colspan="2">10,000 MT/yr CO2eq for industrial facilities</td></tr>
<tr><th colspan="3">Ambient Air Quality Standards for Criteria Pollutants [d]</th></tr>
<tr><td>NO2

1-hour average
annual arithmetic mean</td><td colspan="2">SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards:
0.18 ppm (state)
0.03 ppm (state) and 0.0534 ppm (federal)</td></tr>
<tr><td>PM10
24-hour average
annual average</td><td colspan="2">10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation)
1.0 $\mu g/m^3$</td></tr>
<tr><td>PM2.5
24-hour average</td><td colspan="2">10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation)</td></tr>
<tr><td>SO2
1-hour average
24-hour average</td><td colspan="2">0.25 ppm (state) & 0.075 ppm (federal – 99th percentile)
0.04 ppm (state)</td></tr>
<tr><td>Sulfate
24-hour average</td><td colspan="2">25 $\mu g/m^3$ (state)</td></tr>
<tr><td>CO

1-hour average
8-hour average</td><td colspan="2">SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards:
20 ppm (state) and 35 ppm (federal)
9.0 ppm (state/federal)</td></tr>
<tr><td>Lead
30-day Average
Rolling 3-month average
Quarterly average</td><td colspan="2">1.5 $\mu g/m^3$ (state)
0.15 $\mu g/m^3$ (federal)
1.5 $\mu g/m^3$ (federal)</td></tr>
</table>

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day; ppm = parts per million; $\mu g/m^3$ = microgram per cubic meter; ≥ = greater than or equal to
MT/yr CO2eq = metric tons per year of CO2 equivalents; > = greater than

Discussion

Upon initial examination of the proposed project, the main focus of this analysis pertains to establishing BARCT for the multiple stationary source categories in the NOx RECLAIM program. To control NOx emissions from these sources, an assortment of technologies may be applied individually or in combination to meet proposed BARCT, depending on the source category, as follows (in alphabetical order): Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx^{TM}; LoTOx^{TM} with scrubber; NOx reducing additives; NSCR; SCR with or without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection.

The physical changes involved with the type of NOx emission control strategies that are expected to be utilized focus on the installation of new or the modification of existing control equipment. The possibility of these types of NOx control technologies being used to comply with the proposed project and potential secondary adverse air quality and GHG impacts they may generate will be further evaluated in the Draft PEA. The remaining portions of the proposed project are procedural in nature and will not result in any physical changes that could cause an adverse air quality impact.

III. a) No Impact. The SCAQMD is required by law to prepare a comprehensive district-wide AQMP which includes strategies (e.g., control measures) to reduce emission levels to achieve and maintain state and federal ambient air quality standards, and to ensure that new sources of emissions are planned and operated to be consistent with the SCAQMD's air quality goals. The AQMP's air pollution reduction strategies include control measures which target stationary, mobile and indirect sources. These control measures are based on feasible methods of attaining ambient air quality standards. Pursuant to the provisions of both the state and federal Clean Air Acts, the SCAQMD is required to attain the state and federal ambient air quality standards for all criteria pollutants, including PM10 and PM2.5. Although the District is currently classified as in attainment for both state and federal NO_2 ambient air quality standards, NOx is a precursor pollutant to PM10, PM2.5, and ozone. The proposed project implements 2012 AQMP Control Measure #CMB-01 which will bring the NOx RECLAIM program up-to-date with the latest BARCT requirements to achieve, at a minimum, the proposed NOx emission reductions in #CMB-01 (e.g., at least three to five tons per day by 2023). Therefore, the proposed project will not obstruct or conflict with the implementation of the 2012 AQMP.

Although the proposed project has the potential to temporarily increase criteria pollutants and TAC emissions (as diesel PM) that could exceed the air quality significance thresholds for construction activities, the proposed project is not expected to interfere with achieving at least three to five tons per day of NOx emission reductions by the year 2023, which is consistent with the goals of the 2012 AQMP to achieve additional NOx emission reductions (and reduce NOx precursors as PM 2.5 and PM10) from stationary sources, which will assist in attaining state and federal PM2.5 and PM10 ambient air quality standards. Further, the temporary increase in criteria pollutant and TAC emissions (as diesel PM) due to construction is not expected to impede the emission reduction goals of the 2012 AQMP because the inventory prepared for the 2012 AQMP already takes into account the future emission estimates from all construction activities associated with implementing the proposed control measures[8]. Further, implementation of all other SCAQMD NOx rules along with AQMP control measures, when considered together, is expected to reduce NOx emissions throughout the region overall by 2023. Therefore, implementing the proposed project will not conflict or obstruct implementation of the AQMP. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

III. b) Potentially Significant Impact. The objective of the proposed project is to reduce NOx emissions from the top NOx emitting stationary sources in the NOx RECLAIM program. The proposed project is estimated to reduce emissions, at a minimum, of up to three to five tons per day of NOx by 2023 from these affected sources. Compliance with the proposed project is expected to be achieved by applying a wide assortment of NOx technologies, either individually or in combination on the affected sources.

Implementation of the proposed project is expected to involve construction activities related to the installation or modification of the aforementioned NOx control technologies at the top NOx emitting facilities. The proposed project may also involve the construction of new buildings or other structures as part of installation or modification of the NOx controls. Construction-related activities are also expected to generate emissions from worker vehicles, trucks, and construction equipment. Due to the large scale of construction that would be expected from implementing the proposed project, project-specific construction emissions are potentially significant.

While the operational-related activities are expected to reduce emissions of NOx, a simultaneous increase in emissions of other criteria pollutants are expected from operations of stationary support equipment associated with the installed or modified NOx control equipment, as well as operational emissions associated with periodic truck deliveries of supplies and waste haul trips associated with operation and maintenance of the NOx control equipment. Thus, the air quality impacts associated with the construction and operational phases of the proposed project are potentially significant and will be evaluated in the Draft PEA.

III. c) & g) Potentially Significant Impact. The anticipated NOx emission reductions that would result from implementing the proposed project are expected to improve the overall air quality in the Basin by enhancing the probability of attaining and maintaining state and federal ambient air quality standards for PM10 and PM2.5. The primary effect of implementing the proposed project would be the installation of various types of air pollution control equipment to reduce NOx emissions. Because construction equipment may be utilized to install air pollution control equipment, air pollutants, including GHG emissions, would be generated during their use. Some types of air pollution control equipment contemplated by the proposed project could have the potential to create secondary adverse air quality impacts, including GHG emissions. For this reason, operational activities associated with the proposed project also have the potential to increase emissions of air pollutants and GHGs. Thus, while the purpose of the proposed project is to reduce NOx emissions from the top NOx emitting facilities in the NOx RECLAIM program, a simultaneous increase in GHG emissions could occur from the operation of some

[8] SCAQMD Final Program Environmental Impact Report for the 2012 Air Quality Management Plan, SCH# 2012061093, November 2012. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2012/aqmp-2012

types of air pollution control equipment, if installed. Thus, the secondary construction and operation impacts associated with reducing NOx have the potential for creating significant adverse cumulative air quality impacts that will be evaluated in the Draft PEA. These potential increases will also be evaluated in the Draft PEA as part of the cumulative impacts discussion.

III. d) Potentially Significant Impact. Emission sources associated with the construction-related activities as a result of implementing the proposed project may temporarily emit TACs. Further, emissions sources associated with the operational-related activities as a result of implementing the proposed project may also emit TACs. The impact of these emissions on sensitive populations, including individuals at hospitals, nursing facilities, daycare centers, schools, and elderly intensive care facilities, as well as residential and off-site occupational areas, will be evaluated in the Draft PEA.

III. e) Potentially Significant Impact. The installation of NOx control equipment could result in combustion-source criteria pollutant emissions from construction activity through the use of heavy-duty construction equipment and from vehicle trips generated by construction workers/haul trucks traveling to and from the project site, as well as fugitive dust emissions related to site work and general grading. Mobile source emissions, primarily NO_x and diesel PM, typically result from the use of diesel-fueled construction equipment such as graders, scrapers, bulldozers, wheeled loaders, cranes, etc. During structure erection/finishing phases, paving operations and the application of architectural coatings (e.g., paints) and other building materials, VOCs would be released. Operation-period impacts, which could include criteria pollutant and TAC emissions from permitted stationary sources, may also occur. Depending on the type of control equipment installed, the proposed project could potentially result in an increase in vehicle trips (both passenger vehicles and trucks) on local roadways, which could in turn result in an increase in operational-period criteria pollutant emissions. As such, the impacts of implementing the proposed project could create objectionable odors affecting a substantial number of people. Thus, the potential impacts of objectionable odors affecting a substantial number of people will be analyzed in the Draft PEA.

III. f) No Impact. The proposed project will be required to comply with all applicable SCAQMD, CARB, and EPA rules and regulations. Thus, the proposed project is not expected to diminish an existing air quality rule or future compliance requirements. Further, adopting and implementing the proposed project enhances existing air pollution control rules that are expected to assist the SCAQMD in its efforts to attain and maintain with a margin of safety the state and federal ambient air quality standards for PM10 and PM2.5. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

III. h) Less Than Significant Impact. As mentioned in the discussion in Section III. b), c) and g), construction equipment may be utilized as part of implementing the proposed project and as such, GHG emissions would be generated during their use. Although the primary effect of installing air pollution control equipment is to reduce NOx emissions, some types of control equipment contemplated by the proposed project could also have the potential to create secondary adverse air quality impacts, including GHG emissions. While the purpose of the proposed project is to reduce NOx emissions from the top NOx emitting facilities in the NOx RECLAIM program, a simultaneous increase in GHG emissions could occur from the operation of some types of air pollution control equipment, if installed.

In December 2010, CARB adopted regulations establishing a cap and trade program for the largest sources of GHG emissions in the state that altogether are responsible for about 85 percent of California's GHGs. While the proposed project would not be subject to a GHG reduction plan, all of the affected facilities are currently subject to individual GHG emission reductions pursuant to AB32, the state-wide GHG reduction plan. Among these facilities are fossil-fuel fired power plants, including both plants that generate power within California's borders, and those located outside of California that generate power imported to the state. GHG emissions from this universe of sources were capped for 2013 at a level approximately two percent below the emissions level forecast for 2012, and the cap will steadily decrease at a rate of two to three percent annually from now to 2020. Sources regulated by the cap must reduce their GHG emissions or buy credits from others who have done so. This means that the any additional power needed to operate air pollution control equipment as a result of the proposed project cannot result in an increase in GHG emissions from the increased use of third-party power, compared to GHG emissions at the time of issuance of this NOP/IS. Further, even in the event that some of the affected facilities may experience increases in GHG emissions as a result of implementing the proposed project, the affected facilities would still be required to comply with their overall GHG reduction requirements pursuant to AB32. For these reasons, the proposed project would not conflict with AB32 as well as any applicable GHG reduction plan, policy, and regulations that have been adopted to implement AB32. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since less than significant impacts were identified for this issue, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to air quality and GHGs may occur from implementing the proposed project and thus, impact issues III. b), c), d), e), and g) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IV. BIOLOGICAL RESOURCES. Would the project:				
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
b)	Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑
c)	Have a substantial adverse effect on federally protected wetlands as defined by §404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☐	☑
d)	Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☐	☑
e)	Conflicting with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☐	☑
f)	Conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☐	☑

Significance Criteria

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.

- The project adversely affects aquatic communities through construction or operation of the project.

Discussion

IV. a), b), c), & d) No Impact. The proposed project would only affect units operating at the top NOx emitting facilities in the NOx RECLAIM program facilities with locations scattered throughout the District. All of the affected units operating at existing facilities are located primarily in developed industrial areas, which have already been greatly disturbed and paved. These areas currently do not support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found within close proximity to the affected facilities. Therefore, the proposed project would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely in the SCAQMD's jurisdiction. The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions. A conclusion in the Final Program EIR for the 2012 AQMP was that population growth in the region would have greater adverse effects on plant species and wildlife dispersal or migration corridors in the basin than SCAQMD regulatory activities, (e.g., air quality control measures or regulations). In addition, by reducing air pollutants, biological resources will benefit. Moreover, the current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

IV. e) & f) No Impact. The proposed project is not envisioned to conflict with local policies or ordinances protecting biological resources or local, regional, or state conservation plans. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Additionally, the proposed project will not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan, and would not create divisions in any existing communities because all activities associated with complying with the proposed project will occur at existing industrial facilities. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant biological resources impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant biological resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
V. CULTURAL RESOURCES. Would the project:				
a) Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☐	☐	☑
b) Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☐	☑
c) Directly or indirectly destroy a unique paleontological resource, site, or feature?	☐	☐	☐	☑
d) Disturb any human remains, including those interred outside formal cemeteries?	☐	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance to a community or ethnic or social group.
- Unique paleontological resources are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

Discussion

V. a) No Impact. There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. Since construction-related activities associated with the implementation of the proposed project are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved, no impacts to historical resources are expected to occur as a result of implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

V. b), c), & d) No Impact. Installing or modifying add-on controls and other associated equipment to comply with the proposed project may require disturbance of previously disturbed areas at the affected existing industrial facilities. However, since construction-related activities are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved, the proposed project is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources. Furthermore, it is envisioned that these areas are already either devoid of significant cultural resources or whose cultural resources have been previously disturbed. Therefore, the proposed project has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. The proposed project is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the District. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant cultural resources impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant cultural resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VI.	**ENERGY.** Would the project:				
a)	Conflict with adopted energy conservation plans?	☐	☐	☐	☑
b)	Result in the need for new or substantially altered power or natural gas utility systems?	☑	☐	☐	☐
c)	Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☑	☐	☐	☐
d)	Create any significant effects on peak and base period demands for electricity and other forms of energy?	☑	☐	☐	☐
e)	Comply with existing energy standards?	☐	☐	☐	☑

Significance Criteria

Impacts to energy and mineral resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

Discussion

The proposed project would reduce emissions of NOx from various stationary sources at facilities that are the top NOx emitters in the NOx RECLAIM program. The expected options for compliance are either installing or modifying air pollution control equipment appropriate to the type of process unit. Further, it is expected that the installation and operation of any equipment used to comply with the proposed project will also comply with all applicable existing energy standards.

VI. a) & e) No Impact. The proposed project is not subject to any existing energy conservation plans. If a facility that is subject to Regulation XX and the proposed project is also subject to energy conservation plans, it is not expected that the proposed project will affect in any way or interfere with that facility's ability to comply with its energy conservation plan or energy standards. Further, project construction and operation activities will not utilize non-renewable energy resources in a wasteful or inefficient manner. Accordingly, these impact issues will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for these issues, no mitigation measures are necessary or required.

VI. b), c) & d. **Potentially Significant Impact.** Installation or modification of air pollution control equipment to comply with the proposed project is expected to increase demand for gasoline and diesel fuel to operate construction equipment and to fuel worker vehicles and haul/delivery trucks. In addition, installation or modification of air pollution control equipment to comply with the proposed project is also expected to increase demand for energy used (e.g., electricity) for operating the primary equipment as well as support equipment such as pumps, fans, controllers, et cetera. Any additional electricity required is typically either supplied by each affected facility's cogeneration units, for those that have them, or by the local electrical utility, as appropriate. It is possible that some facilities may need new or substantially altered power utility systems to be built to accommodate any additional electricity demands created by the proposed project. In some cases, an increase in natural gas use may also be needed for operations subject to the proposed project. Finally, operation and maintenance activities associated with operating the installed or modified air pollution control equipment may also increase demand for gasoline and diesel fuel for worker vehicles and haul/delivery trucks.

Based upon these considerations, significant adverse impacts to energy may occur from the implementation of the proposed project and thus, impact issues VI. b), c), and d) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VII. GEOLOGY AND SOILS. Would the project:				
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☐	☑
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☐	☑
• Seismic–related ground failure, including liquefaction?	☐	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☑
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater?	☐	☐	☐	☑

Significance Criteria

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, compaction or over covering of large amounts of soil.

- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.
- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.

Discussion

VII. a) No Impact. Since the proposed project would result in construction activities at existing RECLAIM facilities located in developed industrial settings to install or modify NOx control equipment, little site preparation is anticipated that could adversely affect geophysical conditions in the jurisdiction of the SCAQMD. Southern California is an area of known seismic activity. Accordingly, the installation of add-on controls at existing affected facilities to comply with the proposed project is expected to conform to the Uniform Building Code and all other applicable state and local building codes. As part of the issuance of building permits, local jurisdictions are responsible for assuring that the Uniform Building Code is adhered to and can conduct inspections to ensure compliance. The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The basic formulas used for the Uniform Building Code seismic design require determination of the seismic zone and site coefficient, which represents the foundation condition at the site. The Uniform Building Code requirements also consider liquefaction potential and establish stringent requirements for building foundations in areas potentially subject to liquefaction. Thus, the proposed project would not alter the exposure of people or property to geological hazards such as earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structures to the risk of loss, injury, or death involving the rupture of an earthquake fault, seismic ground shaking, ground failure or landslides is not anticipated. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

VII. b) No Impact. Since add-on controls will likely be installed at existing developed facilities, during construction of the proposed project, a slight possibility exists for temporary erosion resulting from excavating and grading activities, if required. These activities are expected to be minor since the existing facilities are generally flat and have previously been graded and paved. Further, wind erosion is not expected to occur to any appreciable extent, because operators at dust generating sites would be required to comply with the best available control measure (BACM) requirements of SCAQMD Rule 403 – Fugitive Dust. In general, operators must control fugitive dust through a number of soil stabilizing measures such as watering the site, using chemical soil stabilizers, revegetating inactive sites, etc. The proposed project involves the installation or modification of add-on control equipment at existing facilities, so that grading could be required to provide stable foundations. Potential air quality impacts related to grading are addressed elsewhere in this Initial Study (as part of construction air quality impacts). No unstable earth conditions or changes in geologic substructures are expected to result from implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

VII. c) No Impact. Since the proposed project will affect existing facilities, it is expected that the soil types present at the affected facilities will not be made further susceptible to expansion or liquefaction. Furthermore, subsidence is not anticipated to be a problem since only minor excavation, grading, or filling activities are expected occur at affected facilities. Additionally, the affected areas are not envisioned to be prone to new landslide impacts or have unique geologic features since the affected equipment units are located at existing facilities in industrial areas. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

VII. d) & e) No Impact. Since the proposed project will affect equipment units at existing facilities located in industrial zones, it is expected that people or property will not be exposed to new impacts related to expansive soils or soils incapable of supporting water disposal. Further, typically each affected facility has some degree of existing wastewater treatment systems that will continue to be used and are expected to be unaffected by the proposed project. Sewer systems are available to handle wastewater produced and treated by each affected facility. Each existing facility affected by the proposed project does not require installation of septic tanks or alternative wastewater disposal systems. As a result, the proposed project will not require facility operators to utilize septic systems or alternative wastewater disposal systems. Thus, implementation of the proposed project will not adversely affect soils associated with a septic system or alternative wastewater disposal system. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant geology and soils impacts are not expected from the implementation of the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant geology and soils impacts were identified for any of the issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant With Mitigation**	**Less Than Significant Impact**	**No Impact**
VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, and disposal of hazardous materials?	☑	☐	☐	☐
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset conditions involving the release of hazardous materials into the environment?	☑	☐	☐	☐

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
c)	Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☑	☐	☐	☐
d)	Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☐	☑	☐
e)	For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☑
f)	Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
g)	Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☐	☐	☑
h)	Significantly increased fire hazard in areas with flammable materials?	☑	☐	☐	☐

Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.

- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

Discussion

VIII. a) & b) Potentially Significant Impact. In general, the major types of public safety risks associated with hazards and hazardous materials consist of impacts resulting from toxic substance releases, fires, and explosions. At the affected RECLAIM facilities, a number of hazardous materials are currently in use. However, the proposed project may alter the hazards associated with these facilities because new or modified air pollution control equipment and related components could be installed at any or all of the affected facilities such that their operations may increase the quantity of hazardous materials (e.g., catalysts, scrubbing agents) used by the control equipment. In addition, any increases in the shipping, handling, storing, and disposing of hazardous materials inherently poses a certain risk of a release to the environment. Thus, the routine transport of hazardous materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project.

For example, if the control option chosen by each affected facility operator involves the installation of a wet gas scrubber, the proposed project may alter the transportation modes for catalyst and scrubbing agent feedstock and any other associated chemicals to/from the existing facilities. In addition, since SCR and SNCR technologies utilize ammonia, a toxic air contaminant (TAC) and acutely hazardous material, adverse hazard and hazardous materials impacts could occur as a result of the use, transport and storage of ammonia as well as the potential for an accidental release of ammonia into the environment. Moreover, the utilization of ammonia in these technologies can release unreacted ammonia referred to ammonia slip.

For these reasons, implementation of the proposed project may alter the hazards associated with the existing affected facilities. Therefore, potential hazards impacts as a result of implementing the proposed project are potentially significant and will be addressed in the Draft PEA.

VIII. c) Potentially Significant Impact. Some affected facilities may be located within one-quarter mile of a sensitive receptor (e.g., a day care center). Therefore, a potential for significant impacts from hazardous emissions or the handling of acutely hazardous materials, substances and wastes near sensitive-receptors may occur and will be addressed in the Draft PEA.

VIII. d) Less Than Significant Impact. Government Code §65962.5 refers to the "Hazardous Waste and Substances Site List," which is a list of facilities that may be subject to the Resource Conservation and Recovery Act (RCRA) corrective action program. While none of the affected facilities are included on the list prepared by the Department of Toxic Substances Control (DTSC) pursuant to Government Code §65962.5, some of the facilities are included on a list of RCRA-permitted sites that require corrective action as identified by DTSC. Furthermore, some of the affected facilities may be subject to corrective action under the Spill Cleanup Program (SCP) formerly "Spills, Leaks, Investigation & Cleanup (SLIC) Program" administered by the Regional Water Quality Control Board (RWQCB) pursuant to California Water Code §13304.

In the event that the installation of new or modification of existing air pollution control equipment would involve soil disturbing activities such as grading and excavation during construction of the proposed project, there is the potential for uncovering some contaminated soil. Contaminated soil is defined in SCAQMD Rule 1166 - Volatile Organic Compound Emissions From Decontamination of Soil, as soil with the potential to meet or exceed a VOC concentration of 50 ppmv. Rule 1166 includes requirements for SCAQMD notification at least 24 hours prior to the start of excavation activities, monitoring (at least once every 15 minutes, within three inches of the excavated soil surface), as well as implementation of a mitigation plan when VOC-contaminated soil is detected. To ensure compliance with SCAQMD Rule 1166, the affected facility or a construction contractor will need to obtain a pre-approved SCAQMD Rule 1166 VOC-Contaminated Soil Mitigation Plan (Plan) in order to assure that fugitive emissions will be controlled prior to the start of excavation activities. In general, a SCAQMD Rule 1166 Plan will require the contaminated soil pile to be covered with heavy plastic sheeting and will include watering requirements to assure the soil remains moist and will require removal of the VOC-contaminated soils from the disturbed site within 30 days from the time of excavation.

Soil remediation activities are also under the jurisdiction of the RWQCB and are implemented via a Soil Management Plan for the management of small quantities of contaminated soil. Following SCAQMD approval of a Rule 1166 Plan, a Soil Management Plan will need to be submitted to the RWQCB for approval. The RWQCB, when considering the Soil Management Plan, relies on the analysis in this CEQA document and the SCAQMD Rule 1166 Plan.

In the event that any excavated soils contain concentrations of certain substances, such as heavy metals and hydrocarbons, the handling, processing, transportation and disposal of the contaminated soil would also be subject to applicable hazardous waste regulations (i.e., Title 22 of the California Code of Regulations and other local and federal rules). Title 22, Division 4.5 - Environmental Health Standards for the Management of Hazardous Waste has multiple requirements for hazardous waste characterization, handling, transport, and disposal, such as requirements to use approved disposal and treatment facilities, to use certified hazardous waste transporters, and to have manifests for tracking the hazardous materials. If discovered, contaminated excavated soil would be properly characterized to determine an appropriate offsite processing method(s). These methods may include recycling of the soil if it is considered a non-hazardous waste, off-site treatment to reduce the contaminant concentrations to non-hazardous levels so that the treated soil could be used as landfill cover, or disposal as a hazardous waste at a permitted hazardous waste facility.

In addition, there are other regulatory requirements that address the discovery and remediation of contaminated sites, including the discovery of such sites during construction activities. Further, health and safety plans, worker training, and various other activities which serve to protect workers from exposure to contamination are also required. The following federal and state regulatory requirements are specific to worker protection and contaminated soil discovery:

- Hazardous Waste Operations and Emergency Response Standard (HAZWOPER, Fed-OSHA, 29 CFR 1910.120 and Cal-OSHA HAZWOPER, 8 CCR 5192) including the requirements for health and safety plans, worker training, evaluation of the potential for chemical exposure, and physical hazards at the site.

- Resource Conservation and Recovery Act and Associated Hazardous and Solid Waste Amendments (40 CFR 260) are the federal laws and regulations that govern the generation, transportation, treatment, and disposal of hazardous waste.

- Hazardous Waste Control Law (California Health and Safety Code, Chapter 6.5) governs the generation, transportation, treatment, and disposal of hazardous waste.

- Cal-OSHA Construction Worker Safety Orders in Title 8 CCR including Permissible Exposure Levels (8 CCR 5155), injury and illness prevention plans, and workplace safety.

Hazardous wastes from the existing affected facilities are required to be managed in accordance with applicable federal, state, and local rules and regulations. Thus, while the types of additional waste that may be generated from implementing the proposed project could potentially change from the existing setting, the affected facilities would still be required to comply with all of the aforementioned regulations. For example, if the use of a new or increased use of an existing catalyst is needed to operate the installed or modified air pollution control equipment, for those affected facilities which already use catalyst for other operational activities on-site, the additional collected spent catalyst will continue to be handled in the same manner as currently handled such that it will be disposed and/or recycled at approved facilities. Further, if any of other affected facilities are new to handling catalyst waste, the same disposal/recycling procedures are expected to be followed.

For any affected RECLAIM facility that is designated pursuant to Government Code §65962.5 as a large quantity generator of hazardous waste, complying with the proposed project will not alter in any way how each facility would manage their hazardous wastes and each affected facility would be expected to continue to be managed in accordance with all applicable federal, state, and local rules and regulations. Similarly, for any affected RECLAIM facility that is not designated pursuant to Government Code §65962.5 as a large quantity generator, implementing the proposed project would not change a facility's status regarding hazardous waste generation. Thus, implementing the proposed project would not be expected to interfere with site cleanup activities or create additional site contamination. Thus, for the aforementioned reasons, less than significant hazards impacts from the soil disturbing activities as well as the disposal and/or recycling of hazardous materials are expected from implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. e) No Impact. Federal Aviation Administration, 14 CFR Part 77 – Safe, Efficient Use and Preservation of the Navigable Airspace[9], provides information regarding the types of projects that may affect navigable airspace. Projects may adversely affect navigable airspace if they involve construction or alteration of structures greater than 200 feet above ground level within a specified distance from the nearest runway or objects within 20,000 feet of an airport or seaplane base with at least one runway more than 3,200 feet in length and the object would exceed a slope of 100:1 horizontally (100 feet horizontally for each one foot vertically from the nearest point of the runway).

[9] Department of Transportation. Federal Aviation Administration, 14 CFR Part 77 [Docket No. FAA–2006–25002; Amendment No. 77–13] RIN 2120–AH31. *Safe, Efficient Use and Preservation of the Navigable Airspace*. 42296 Federal Register / Vol. 75, No. 139 / Wednesday, July 21, 2010 / Rules and Regulations. http://www.gpo.gov/fdsys/pkg/FR-2010-07-21/pdf/2010-17767.pdf.

Construction activities from implementing the proposed project are expected to occur within the existing confines of the affected facilities. However, some of these facilities may be located within two miles of an airport (either public or private) and are located within an airport land use plan. Nonetheless, the installation of the NOx control devices is expected to be constructed according to the all appropriate building, land use and fire codes and operated at a low enough height relative to existing flight patterns so that the structure would not interfere with plane flight paths consistent with Federal Aviation Regulation, Part 77. Such codes are designed to protect the public from hazards associated with normal operation. Therefore, the proposed project is not expected to result in a safety hazard for people residing or working in the area of the affected facilities even if construction would occur within the vicinity of an airport. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. f) No Impact. Health and Safety Code §25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

- Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;
- Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the California Office of Emergency Services;
- Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;
- Procedures to notify the necessary persons who can respond to an emergency within the facility;
- Details of evacuation plans and procedures;
- Descriptions of the emergency equipment available in the facility;
- Identification of local emergency medical assistance; and
- Training (initial and refresher) programs for employees in:
  1. The safe handling of hazardous materials used by the business;
  2. Methods of working with the local public emergency response agencies;
  3. The use of emergency response resources under control of the handler;
  4. Other procedures and resources that will increase public safety and prevent or mitigate a release of hazardous materials.

In general, every county or city and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In conjunction with the California Office of Emergency Services, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area. Emergency response plans are typically prepared in coordination with the local city or county emergency plans to ensure the safety of not only the public (surrounding local communities), but the facility employees as well.

The existing industrial facilities affected by the proposed project already have their own emergency response plans in place. The proposed project would not impair implementation of, or physically interfere with any adopted emergency response plan or emergency evacuation plan. However, depending on the physical changes that may be taken in order to reduce NOx emissions such as installing NOx control equipment, an affected facility's emergency response plan may need to be updated to accommodate any changes that may occur. For example, if additional storage of hazardous materials (e.g., ammonia) is needed in order to operate a new SCR unit at an affected facility, then such modifications may require a revision to an affected facility's emergency response plan. However, these modifications would not be expected to interfere with the existing emergency response procedures in place.

Thus, the proposed project is not expected to impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan, but may require changes or updates. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. g) No Impact. Flammable materials such as natural gas, diesel and gasoline are currently used at several of the affected facilities and additional fuels may be used during either construction or operation of the proposed project. While the hazards associated with these fuels could result in a torch fire in the event that a release occurred and caught fire, a torch fire would be expected to remain on-site because the affected RECLAIM facilities are located at existing, established industrial sites in urban areas where wildlands are not prevalent. In addition, no substantial or native vegetation typically exists on or near the affected facilities (specifically because they could be a fire hazard), so the proposed project is not expected to expose people or structures to wild fires. For these reasons, the proposed project is not expected to increase the existing risk of fire hazards in areas with flammable brush, grass, or trees, so there would be no public exposure to fire hazards and as such no risk of loss or injury associated with wildland fires would be expected. Accordingly, this impact issue will not be further evaluated in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. h) Potentially Significant Impact. The Uniform Fire Code and Uniform Building Code set standards intended to minimize risks from flammable or otherwise hazardous materials. Local jurisdictions are required to adopt the uniform codes or comparable regulations. Local fire agencies require permits for the use or storage of hazardous materials and permit modifications for proposed increases in their use. Permit conditions depend on the type and quantity of the hazardous materials used. Permit conditions may include, but are not limited to, specifications for sprinkler systems, electrical systems, ventilation, and containment. The fire departments make annual business inspections to ensure compliance with permit conditions and other appropriate regulations. Further, businesses are required to report increases in the storage or use of flammable and otherwise hazardous materials to local fire departments. Local fire departments ensure that adequate permit conditions are in place to protect against the potential risk of upset.

For any affected facility that installs NOx control equipment as a result of implementing the proposed project, the increased transport, handling, or use of flammable or hazardous materials could occur. For example, for control equipment that utilizes ammonia (e.g., SCR or SNCR), explosion risks resulting from the industrial handling of aqueous ammonia solutions could increase. As such, the potential for increased probability of explosion, fire, or other hazards will be addressed in the Draft PEA. Impacts related to public exposure to toxic air contaminants will be addressed in the "Air Quality and Greenhouse Gas" section of the Draft PEA.

Based upon these considerations, significant adverse impacts to hazards and hazardous materials may occur from implementing the proposed project and thus, impact issues VIII. a), b), c), and h) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IX. HYDROLOGY AND WATER QUALITY. Would the project:				
a) Violate any water quality standards, waste discharge requirements, exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board, or otherwise substantially degrade water quality?	☑	☐	☐	☐
b) Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☑	☐	☐	☐
c) Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site?	☐	☐	☑	☐

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
d) Create or contribute runoff water which would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☑	☐
e) Place housing or other structures within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map, which would impede or redirect flood flows?	☐	☐	☐	☑
f) Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam, or inundation by seiche, tsunami, or mudflow?	☐	☐	☐	☑
g) Require or result in the construction of new water or wastewater treatment facilities or new storm water drainage facilities, or expansion of existing facilities, the construction of which could cause significant environmental effects?	☑	☐	☐	☐
h) Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☑	☐	☐	☐
i) Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project’s projected demand in addition to the provider’s existing commitments?	☑	☐	☐	☐

Significance Criteria

Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Demand:

- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.
- The project increases demand for total water by more than five million gallons per day.

Water Quality:

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

Discussion

IX. a), g) & i) Potentially Significant Impact. In the event that the proposed project is implemented, operators of the affected RECLAIM facilities may install new or modify existing air pollution control equipment to reduce NOx emissions. Operational activities associated with some types of NOx control equipment utilize water such that if there is an increase in the demand for water, a subsequent increase in the amount wastewater discharged at an affected facility may occur. For example, water/steam injection and WGS technology both utilize water in their processes. In addition, operators of the affected RECLAIM facilities could choose to install control equipment that utilize SCR or SNCR, which both utilize ammonia, a TAC and acutely hazardous material, that if spilled, an accidental ammonia release into the environment could cause adverse water quality impacts.

Depending on the type of NOx controls employed, the impacts of the proposed project on each affected facility's wastewater discharge and the Industrial Wastewater Discharge Permit could be potentially significant. Thus, implementing the proposed project may result in the potential for generating increased volumes of wastewater that could adversely affect water quality standards or waste discharge requirements resulting in the need for new or increased wastewater treatment capacity. Accordingly, these topic areas will be evaluated further in the Draft PEA.

IX. b) & h) Potentially Significant Impact. In the event that the proposed project is implemented, operators of the affected RECLAIM facilities may install new or modify existing air pollution control equipment to reduce NOx emissions. Construction activities associated with the proposed project may require site preparation/earthmoving activities such as grading and the limited use of water may be utilized as a dust suppressant. In addition, operational activities associated with some types of NOx control equipment utilize water such that there may be an increase in the demand for water. For example, water/steam injection and WGS technology both utilize water in their processes.

In addition, each affected facility may not have sufficient water supplies available for implementing the proposed project since WGSs could be installed along with NOx control equipment at the affected facilities and WGSs heavily rely on water for their operation. Thus, the need for new or expanded water supply entitlements may be necessary. While it is not possible to predict water availability in the future, existing entitlements and resources in the district are currently at historically low drought levels. Thus, the water demand that would result from implementing the proposed project may result in significant adverse water impacts.

Thus, implementing the proposed project would require additional water, some of which could come from ground water supplies, require new water supply facilities, or require an expansion of existing water supply facilities. Accordingly, these topic areas are potentially significant and as such, will be evaluated further in the Draft PEA.

IX. c) & d) Less Than Significant Impact. Changes to each affected RECLAIM facility's storm water collection systems are expected to be less than significant since most of the changes that may be associated with the proposed project will occur within existing units (e.g., by installing NOx control equipment). Further, typically most of the areas likely to be affected by the proposed project are currently paved and are expected to remain paved. Any new units constructed will be curbed and the existing units will remain curbed to contain any runoff. Any runoff occurring will continue to be handled by each affected facility's wastewater system and sent to an on-site wastewater treatment system prior to discharge. The surface water runoff is expected to be handled with each affected facility's current wastewater treatment system. Storm water runoff will be collected and discharged in accordance with each facility's discharge permit terms and conditions. Storm Water Pollution Prevention Plans may need to be updated, as necessary, to reflect any operational modifications and included additional Best Management Practices, if required. Thus, the proposed project would not be expected to substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site. Further, any construction that may occur as a result of implementing the proposed project will occur at the existing affected facilities, and as such, would not involve modifications that would alter the course of a stream or river.

Therefore, less than significant storm water quality impacts may result from the operation of the proposed project. Accordingly, these impact issues will not be further evaluated in the Draft PEA. Further, since no significant impacts were identified for these issues, no mitigation measures are necessary or required.

IX. e) No Impact. Once implemented, the proposed project is not expected to require additional workers, except during construction activities. Further, the proposed project is expected to involve construction activities located at the affected RECLAIM facilities and would not require the construction of any new housing so it would not place new housing in 100-year flood areas as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood delineation map. Since the proposed project would not require locating new facilities within a flood zone, it is not expected that implementation of the proposed project would expose people or property to any known water-related flood hazards.

As a result, the proposed project would not be expected to create or substantially increase risks from flooding or expose people or structures to significant risk of loss, injury or death involving flooding. Consequently, this topic will not be evaluated further in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

IX. f) No Impact. The proposed project does not require construction in areas that could be affected by tsunamis. Of the RECLAIM facilities affected by the proposed project, some are located near the Ports of Long Beach, Los Angeles, and San Pedro. The port areas are protected from tsunamis by the construction of breakwaters. Construction of breakwaters combined with the distance of each facility from the water is expected to minimize the potential impacts of a tsunami or seiche so that no significant impacts are expected. The proposed project does not require construction of facilities in areas that are susceptible to mudflows (e.g., hillside or slope areas). Existing affected facilities that are currently located on hillsides or slope areas may be susceptible to mudflow, but this would be considered part of the existing setting. As a result, the proposed project is not expected to generate significant adverse mudflow impacts. Finally, the proposed project will not affect in any way any potential flood hazards inundation by seiche, tsunami, or mud flow that may already exist at the affected RECLAIM facilities. Accordingly, this impact issue will not be further evaluated in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to hydrology and water quality may occur from implementing the proposed project and thus, impact issues IX. a), b), g), h), and i) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
X. LAND USE AND PLANNING. Would the project:				
a) Physically divide an established community?	☐	☐	☐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☐	☑

Significance Criteria

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

Discussion

X. a) No Impact. The proposed project does not require the construction of new facilities, but any physical effects that will result from the proposed project, will occur at existing RECLAIM facilities located in heavy industrial areas and would not be expected to go beyond existing boundaries. Thus, implementing the proposed project will not result in physically dividing any established communities.

X. b) No Impact. There are no provisions in the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Further, the proposed project would be consistent with the typical industrial zoning of the affected facilities. Typically, all proposed construction activities are expected to occur within the confines of the existing facilities. The proposed project would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Further, no new development or alterations to existing land designations will occur as a result of the implementation of the proposed project. Therefore, present or planned land uses in the region will not be affected as a result of implementing the proposed project.

Based upon these considerations, significant land use planning impacts are not expected from the implementation of the proposed project, and thus, will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for any of these issues, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XI.	**MINERAL RESOURCES.** Would the project:				
a)	Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☐	☑
b)	Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on mineral resources will be considered significant if any of the following conditions are met:

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Discussion

XI. a) & b) No Impact. There are no provisions in the proposed project that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Based upon these considerations, significant mineral resource impacts are not expected from the implementation of the proposed project, and thus, will not be further analyzed in the Draft PEA. Since no significant mineral resource impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XII. NOISE. Would the project result in:				
a) Exposure of persons to or generation of permanent noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☑	☐
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☑	☐
c) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☑	☐

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
d) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑	☐

Significance Criteria

Noise impact will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

Discussion

XII. a), b), & c) Less Than Significant Impact. Modifications or changes associated with the implementation of the proposed project will take place at existing RECLAIM facilities that are located in heavy industrial settings. The existing noise environment at each of the affected facilities is typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises. Construction activities associated with implementing the proposed project may generate some noise associated with the use of construction equipment and construction-related traffic. However, noise from the proposed project is not expected to produce noise in excess of current operations at each of the existing facilities. If NOx control devices are installed or existing devices are modified, the operations phase of the proposed project may add new sources of noise to each affected facility. However, control devices are not typically equipment that generate substantial amounts of noise. Nonetheless, for any noise that may be generated by the control devices, it is expected that each facility affected will comply with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA (Cal/OSHA) have established noise standards to protect worker health. These potential noise increases are expected within the allowable noise levels established by the local noise ordinances for industrial areas, and thus are expected to be less than significant. Therefore, less than significant noise impacts are expected to result from the operation of the proposed project will not be further evaluated in the Draft PEA. Accordingly, these impact issues will not be further evaluated in the Draft PEA.

XII. d) Less Than Significant Impact. Though some of the facilities affected by the proposed project are located at sites within an airport land use plan, or within two miles of a public airport, the addition of new or modification of existing NOx control equipment would not expose people residing or working in the project area to the same degree of excessive noise levels associated with airplanes. All noise producing equipment must comply with local noise ordinances and applicable OSHA or Cal/OSHA workplace noise reduction requirements. Therefore, less than significant noise impacts are expected to occur at sites located within an airport land use plan, or within two miles of a public airport. Accordingly, this impact issue will not be further evaluated in the Draft PEA.

Based upon these considerations, significant noise impacts are not expected from the implementation of the proposed project and will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for any of these issues, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIII.	**POPULATION AND HOUSING.** Would the project:				
a)	Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?	☐	☐	☐	☑
b)	Displace substantial numbers of people or existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑

Significance Criteria

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

Discussion

XIII. a) No Impact. The construction activities associated with the proposed project at each affected facility are not expected to involve the relocation of individuals, require new housing or commercial facilities, or change the distribution of the population. The reason for this conclusion is that operators of affected facilities who need to perform any construction activities to comply with the proposed project can draw from the large existing labor pool in the local southern California area. Further, it is not expected that the installation of new or the modification of existing NOx control equipment will require new employees during operation of the equipment. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing the proposed project. As a result, the proposed project is not anticipated to generate any significant adverse effects, either direct or indirect, on population growth in the district or population distribution.

XIII. b) & c) No Impact. Because the proposed project includes modifications and/or changes at existing facilities located in heavy industrial settings, the proposed project is not expected to result in the creation of any industry that would affect population growth, directly or indirectly induce the construction of single- or multiple-family units, or require the displacement of people or housing elsewhere in the district.

Based upon these considerations, significant population and housing impacts are not expected from the implementation of the proposed project, and thus, will not be further evaluated in the Draft PEA. Since no significant population and housing impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIV. PUBLIC SERVICES. Would the proposal result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:				
a) Fire protection?	☐	☐	☑	☐
b) Police protection?	☐	☐	☑	☐
c) Schools?	☐	☐	☐	☑
d) Other public facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time or other performance objectives.

Discussion

XIV. a) & b) Less Than Significant Impact. Implementation of the proposed project is expected to cause facility operators to install new or modify existing NOx control devices, all the while continuing current operations at existing affected facilities. The proposed project may result in a greater demand for catalyst, scrubbing agents and other chemicals, which will need to be transported to the affected facilities to support the function of NOx control equipment and stored onsite prior to use. As first responders to emergency situations, police and fire departments may assist local hazmat teams with containing hazardous materials, putting out fires, and controlling crowds to reduce public exposure to releases of hazardous materials. In addition, emergency or rescue vehicles operated by local, state, and federal law enforcement agencies, police and sheriff departments, fire departments, hospitals, medical or paramedic facilities, that are used for responding to situations where potential threats to life or property exist, including, but not limited to fire, ambulance calls, or life-saving calls, may be needed in the event of an accidental release or other emergency. While the specific nature or degree of such impacts is currently unknown, the affected facilities have existing emergency response plans so any changes to those plans would not be expected to dramatically alter how emergency personnel would respond to an accidental release or other emergency. In addition, due the low probability and unpredictable nature of accidental releases, the proposed project is not expected to increase the need or demand for additional public services (e.g., fire and police departments and related emergency services, et cetera) above current levels. Accordingly, these impact issues will not be further evaluated in the Draft PEA.

XIV. c) No Impact. As noted in the previous "Population and Housing" discussion, the proposed project is not expected to induce population growth in any way because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any construction activities that may be necessary at affected facilities and operation of new or modified NOx control equipment is not expected to require additional employees. Therefore, there will be no increase in local population and thus no impacts are expected to local schools or parks. Accordingly, this impact issue will not be further evaluated in the Draft PEA.

XIV. d) No Impact. The proposed project is expected to result in the use of new or modified add-on control equipment for NOx control. Besides permitting the equipment or altering permit conditions by the SCAQMD, there is no need for other types of government services. The proposed project would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population and, therefore, no need for physically altered government facilities. Accordingly, this impact issue will not be further evaluated in the Draft PEA.

Based upon these considerations, significant public services impacts are not expected from the implementation of the proposed project and will not be further evaluated in the Draft PEA. Since no significant public services impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XV. RECREATION.				
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☐	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment or recreational services?	☐	☐	☐	☑

Significance Criteria

Impacts to recreation will be considered significant if:

- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

Discussion

XV. a) & b) No Impact. As discussed earlier under the topic of "Population and Housing," there are no provisions in the proposed project that would affect or increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or the expansion of existing recreational facilities that might have an adverse physical effects on the environment because the proposed project will not directly or indirectly increase or redistribute population. Based upon these considerations, including the conclusion of "no impact" for the topic of "Population and Housing," significant recreation impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVI. SOLID AND HAZARDOUS WASTE. Would the project:				
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☑	☐	☐	☐
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☐	☑

Significance Criteria

The proposed project impacts on solid and hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

Discussion

XVI. a) Potentially Significant Impact. Construction activities associated with installing new or modifying existing NOx control equipment such as demolition and site preparation/grading/excavating could generate solid waste as result of implementing the proposed project. Demolition activities could generate demolition waste while site preparation, grading, and excavating could uncover contaminated soils since the facilities affected by the proposed project are located in existing heavy industrial areas. Excavated soil, which may be contaminated, will need to be characterized, treated, and disposed of offsite in accordance with applicable regulations. Where appropriate, the soil will be recycled if it is considered or classified as non-hazardous waste or it can be disposed of at a landfill that accepts non-hazardous waste. Otherwise, the material will need to be disposed of at a hazardous waste facility. (Potential soil contamination is addressed in the Hazards and Hazardous Materials discussion in Section VIII. d.)

Solid or hazardous wastes generated from construction-related activities would consist primarily of materials from the demolition and/or alteration of any existing structure to make room for the new equipment to be installed. Construction-related waste would be disposed of at a Class II (industrial) or Class III (municipal) landfill. In addition, the generation of solid or hazardous waste could occur if air pollution control equipment is installed that relies on activated carbon, filters, and catalysts to function.

Solid waste impacts would be significant if the additional potential waste volume exceeded the existing capacity of landfills in the District. The potential solid and hazardous waste impacts from implementing the proposed project will be analyzed in the Draft PEA.

XVI. b) No Impact. Implementation of the proposed project is not expected to interfere with the affected RECLAIM facilities' abilities to comply with federal, state, or local statutes and regulations related to solid and hazardous waste handling or disposal. Further, nothing in the proposed project would interfere with the compliance requirements for waste handling or disposal. Thus, this specific topic will not be further evaluated in the Draft PEA. Since no significant solid and hazardous waste impacts were identified for this topic, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to solid and hazardous waste may occur from implementing the proposed project and thus, impact issue XVI. a) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVII. TRANSPORTATION AND TRAFFIC. Would the project:				
a) Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?	☑	☐	☐	☐
b) Conflict with an applicable congestion management program, including but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?	☑	☐	☐	☐
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☐	☑

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
d)	Substantially increase hazards due to a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?	☐	☐	☐	☑
e)	Result in inadequate emergency access?	☐	☐	☐	☑
f)	Conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on transportation and traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- The project conflicts with applicable policies, plans or programs establishing measures of effectiveness, thereby decreasing the performance or safety of any mode of transportation.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

Discussion

XVII. a) & b) Potentially Significant Impact. Construction activities resulting from implementing the proposed project may generate a temporary increase in traffic in the areas of each affected facility associated with construction workers, construction equipment, and the delivery of construction materials. Also, the proposed project may exceed, either individually or cumulatively, the current level of service of the areas surrounding the affected facilities. The impacts of the traffic load and capacity of the street system during construction will be analyzed in the Draft PEA.

The work force at each affected facility is not expected to significantly increase during operations of the proposed project operations because few, if any, new employees are expected to be needed to operate any new or modified NOx control equipment. As a result, operation-related traffic is expected to be limited more towards supply deliveries and waste haul trips, but less than significant. Thus, the operational traffic impacts will not be evaluated further in the Draft PEA.

XVII. c) No Impact. Though some of the facilities that will be affected by the proposed project are located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, actions that would be taken to comply with the proposed project, such as installing new or modifying existing NOx control equipment, are not expected to significantly influence or affect air traffic patterns. Further, the size and type of air pollution control devices that would be installed would not be expected to affect navigable air space. Thus, the proposed project would not result in a change in air traffic patterns including an increase in air traffic levels or a change in location that results in substantial safety risks. As such, this specific topic will not be further evaluated in the Draft PEA. Since no significant transportation and traffic impacts were identified for this topic, no mitigation measures are necessary or required.

XVII. d) & e) No Impact. The siting of each affected facility is consistent with surrounding land uses and traffic/circulation in the surrounding areas of the affected facilities. Thus, the proposed project is not expected to substantially increase traffic hazards or create incompatible uses at or adjacent to the affected facilities. Aside from the temporary effects due to a slight increase in truck traffic for those facilities that will undergo construction activities during installation of air pollution control equipment, the proposed project is not expected to alter the existing long-term circulation patterns. Further, the proposed project is not expected to require a modification to circulation, thus, no long-term impacts on the traffic circulation system are expected to occur. The proposed project is not expected to involve the construction of any roadways, so there would be no increase in roadway design feature that could increase traffic hazards. Emergency access at each affected facility is not expected to be impacted by the proposed project because each affected facility is expected to continue to maintain their existing emergency access gates. Thus, these specific topics will not be further evaluated in the Draft PEA. Since no significant transportation and traffic impacts were identified for this topic, no mitigation measures are necessary or required.

XVII. f) No Impact. Construction and operation activities resulting from implementing the proposed project are not expected to conflict with policies supporting alternative transportation since the proposed project does not involve or affect alternative transportation modes (e.g.

bicycles or buses) because the construction and operation activities related to the proposed project will occur solely in existing industrial areas. Thus, this specific topic will not be further evaluated in the Draft PEA. Since no significant transportation and traffic impacts were identified for this topic, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to transportation and traffic may occur from implementing the proposed project and thus, impact issues XVII. a) and b) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☑	☐	☐	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☑	☐	☐	☐

Discussion

XVIII. a) No Impact. The proposed project is not expected to reduce or eliminate any plant or animal species or destroy prehistoric records of the past. As indicated in the Biological Resources discussion in Section IV., each site affected by the proposed project is part of an existing facility, which has been previously graded, such that the proposed project is not expected to extend into environmentally sensitive areas. In addition, overall air quality improvements that are expected to occur as a result of implementing the proposed project will also be expected to benefit plant and animal life.

XVIII. b) Potentially Significant Impact. The Environmental Checklist indicates that the proposed project has potentially significant adverse impacts on the following topic areas: aesthetics; air quality and GHG emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. The potential for cumulative impacts on these resources will be evaluated in the Draft PEA.

XVIII. c) Potentially Significant Impact. Even though the objective of the proposed project is to reduce NOx emissions from the top emitters in the RECLAIM program, the proposed project may result in secondary effects, emissions of regulated air pollutants, toxic air contaminants, GHGs and may also increase the hazards at some of the affected facilities. The potential for these impacts to have adverse impacts on human beings, either directly or indirectly, will be evaluated in the Draft PEA.

APPENDIX A

PROPOSED AMENDED RULE 2002 – ALLOCATIONS FOR OXIDES OF NITROGEN (NOX) AND OXIDES OF SULFUR (SOX)

The BARCT evaluation and the RTC shaving methodology are ongoing, so a RECLAIM industry's required RTC shave may change due to the public review process. The programmatic RTC shave could range from five to 14 tons per day. To provide a worst case scenario of adverse environmental impacts, the adjustment factors and the Non-tradable/Non-usable NOx RTC adjustment factors in Proposed Amended Rule 2002 subparagraph (f)(1)(B) reflect an RTC shave at the higher end of the range to capture a conservative estimate of potential control technologies needed that could generate secondary environmental impacts. As the staff proposal is being refined, if a lesser RTC shave is proposed, the adverse environmental impacts would be less and the Draft PEA and its alternatives will also be further defined.

(Adopted October 15, 1993)(Amended March 10, 1995)(Amended December 7, 1995)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended May 11, 2001)
(Amended January 7, 2005)(Amended November 5, 2010)
(PAR2002 120214)

PROPOSED AMENDED RULE 2002. ALLOCATIONS FOR OXIDES OF NITROGEN (NO_X) AND OXIDES OF SULFUR (SOx)

(a) Purpose

The purpose of this rule is to establish the methodology for calculating facility Allocations and adjustments to RTC holdings for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).

(b) RECLAIM Allocations

(1) RECLAIM Allocations will begin in 1994.

(2) An annual Allocation will be assigned to each facility for each compliance year starting from 1994.

(3) Allocations and RTC holdings for each year after 2011 are equal to the 2011 Allocation and RTC holdings, as determined pursuant to subdivision (f) unless, as part of the AQMP process, and pursuant to Rule 2015 (b)(1), (b)(3), (b)(4), or (c), the District Governing Board determines that additional reductions are necessary to meet air quality standards, taking into consideration the current and projected state of technology available and cost-effectiveness to achieve further emission reductions.

(4) The Facility Permit or relevant sections thereof shall be re-issued at the beginning of each compliance year to include allocations determined pursuant to subdivisions (c), (d), (e), and (f) and any RECLAIM Trading Credits (RTC) obtained pursuant to Rule 2007 - Trading Requirements for the next fifteen years thereafter and any other modifications approved or required by the Executive Officer.

(c) Establishment of Starting Allocations

(1) The starting Allocation for RECLAIM NO_X and SO_X facilities initially permitted by the District prior to October 15, 1993, shall be determined by the Executive Officer utilizing the following methodology:

Starting Allocation=Σ [A X B_1]+ERCs+External Offsets

where

A = the throughput for each NO_X and SO_X source or process unit in the facility for the maximum throughput year from 1989 to 1992 inclusive; and

B_1 = the applicable starting emission factor for the subject source or process unit as specified in Table 1 or Table 2

(2) (A) Use of 1992 data is subject to verification and revision by the Executive Officer or designee to assure validity and accuracy.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports submitted pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable starting emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information relative to hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other relevant parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District, including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NOx or SOx source will be multiplied by the starting emission factors specified in Table 1 or Table 2. If a lower emission factor was utilized for a given piece of equipment or NOx or SOx source pursuant to Rule 301 - Permit Fees, than the factor in Table 1 or Table 2, the lower factor will be used for determining that portion of the Allocation.

(E) Fuel heating values may be used to convert throughput records into the appropriate units for determining Allocations based on the emission factors in Table 1 or Table 2. If a different unit basis than set forth in Tables 1 and 2 is needed for emissions calculations, the Executive Officer shall use a default heating value to determine source emissions, unless the Facility Permit holder can demonstrate with substantial evidence to the Executive Officer that a different value should be used to determine emissions from that source.

(3) All NO_X and SO_X ERCs generated at the facility and held by a RECLAIM Facility Permit holder shall be reissued as RTCs. RECLAIM facilities will have these RTCs added to their starting Allocations. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule and shall have a rate of reduction for compliance year 2004 and subsequent years determined pursuant to paragraph (f)(1) of this rule.

(4) Non-RECLAIM facilities may elect to have their ERCs converted to RTCs and listed on the RTC Listing maintained by the Executive Officer or designee pursuant to Rule 2007 - Trading Requirements, so long as the written request is filed before July 1, 1994. Such RTCs will be assigned to the trading zone in which the generating facility is located. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years, 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule.

(5) External offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio, will be added to the starting Allocation pursuant to paragraph (c)(1) provided:

(A) The offsets were not received from either the Community Bank or the Priority Reserve.

(B) External offsets will only be added to the starting Allocation to the extent that the Facility Permit holder demonstrates that they have not already been included in the starting Allocation or as an ERC. RTCs issued for external offsets shall not include any offsets in excess of a 1 to 1 ratio required under Regulation XIII - New Source Review.

(C) RTCs generated from the conversion of external offsets shall have a zero rate of reduction for the year 1994 through the year 2000. These RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule, and for compliance year 2004 and subsequent years allocations shall be determined pursuant to paragraph (f)(1) of this rule. The rate of reduction for the year 2001 through year 2003 shall not be applied to new facilities initially totally permitted on or after January 7, 2005.

(D) Existing facilities with units that have Permits to Construct issued pursuant to Regulation II - Permits, dated on or after January 1, 1992, or existing facilities which have, between January 1, 1992 and October 15, 1993, installed air pollution control equipment that was exempt from offset requirements pursuant to Rule 1304 (a)(5), shall have their starting Allocations increased by the total external offsets provided, or the amount that would have been offset if the exemption had not applied.

(E) Existing facilities with units whose reported emissions are below capacity due to phased construction, and/or where the Permit to Operate issued pursuant to Regulation II - Permits, was issued after January 1, 1992, shall have their starting Allocations increased by the total external offsets provided.

(6) If a Facility Permit holder can demonstrate that its 1994 Allocation is less than the 1992 emissions reported pursuant to Rule 301 - Permit Fees, and that the facility was, in 1992, operating in compliance with all applicable District rules in effect as of December 31, 1993, the facility's starting Allocation will be equal to the 1992 reported emissions.

(7) For new facilities initially totally permitted on or after January 1, 1993 but prior to October 15, 1993, the starting Allocation shall be equal to the external offsets provided by the facility to offset emission increases at the facility pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(8) The Allocation for new facilities initially totally permitted on and after October 15, 1993, shall be equal to the total RTCs provided by the facility to offset emission increases at the facility pursuant to Rule 2005- New Source Review for RECLAIM.

(9) The starting Allocation for existing facilities which enter the RECLAIM

program pursuant to Rule 2001 - Applicability, shall be determined by the methodology in paragraph (c)(1) of this rule. The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to the external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio. The Allocation shall not include any emission offsets received from either the Community Bank or the Priority Reserve.

(10) A facility may not receive more than one set of Allocations.

(11) A facility that is no longer holding a valid District permit on January 1, 1994 will not receive an Allocation, but may, if authorized by Regulation XIII, apply for ERCs.

(12) Clean Fuel Adjustment to Starting Allocation

Any refiner who is required to make modifications to comply with CARB Phase II reformulated gasoline production (California Code of Regulations, Title 13, Sections 2250, 2251.5, 2252, 2260, 2261, 2262, 2262.2, 2262.3, 2262.4, 2262.5, 2262.6, 2262.7, 2263, 2264, 2266, 2267, 2268, 2269, 2270, and 2271) or federal requirements (Federal Clean Air Act, Title II, Part A, Section 211; 42 U.S.C. Section 7545) may receive (an) increase(s) in his Allocations except to the extent that there is an increase in maximum rating of the new or modified equipment. Each facility requesting an increase to Allocations shall submit an application for permit amendment specifying the necessary modifications and tentative schedule for completion. The Facility Permit holder shall establish the amount of emission increases resulting from the reformulated gasoline modifications for each year in which the increase in Allocations is requested. The increase to its Allocations will be issued contemporaneously with the modification according to a schedule approved by the Executive Officer or designee (i.e., 1994 through 1997 depending on the refinery). Each increase to the Allocations shall be equal to the increased emissions resulting from the modifications solely to comply with the state or federal reformulated gasoline requirements at the refinery or facility producing hydrogen for reformulated gasoline production, and shall be established according to present and future compliance limits in current District rules or permits. Allocation increases for each refiner pursuant to this paragraph, shall not exceed 5 percent of the refiner's total starting Allocation, unless any refiner emits less than 0.0135 tons of NO_X per thousand barrels of crude processed, in which case the Allocation increases for such refiner shall not exceed 20 percent of that refiner's starting Allocation. The emissions per amount of crude processed will be determined on the basis of information reported to the District pursuant to Rule 301 - Permit Fees, for the same calendar year as the facility's peak activity year for their NO_X starting Allocation.

(d) Establishment of Year 2000 Allocations

(1) (A) The year 2000 Allocations for RECLAIM NO_X and SO_X facilities will be determined by the Executive Officer or designee utilizing the following methodology:

$$\text{Year 2000 Allocation} = \Sigma\,[A \times B_2] + \text{RTCs created from ERCs} + \text{External Offsets},$$

where

A = the throughput for each NO_X or SO_X source or process unit in the facility for the maximum throughput year from 1987 to 1992, inclusive, as reported pursuant to Rule 301 - Permit Fees; and

B_2 = the applicable Tier I year Allocation emission factor for the subject source or process unit, as specified in Table 1 or Table 2.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information on hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NO_X or SO_X source will be multiplied by the Tier I emission factor specified in Table 1 or Table 2. If a factor lower than the factor in Table 1 or Table 2 was utilized for a given piece of equipment or NO_X or SO_X source pursuant to Rule 301, the lower factor will be used for determining that portion of the Allocation.

(E) The fuel heating value may be considered in determining Allocations and will be set to 1.0 unless the Facility Permit holder demonstrates that it should receive a different value.

(F) The year 2000 Allocation is the sum of the resulting products for each piece of equipment or NO_X or SO_X source multiplied by any inventory adjustment pursuant to paragraph (d)(4) of this rule.

(2) For facilities existing prior to October 15, 1993 which enter RECLAIM after October 15, 1993, the year 2000 Allocation will be determined according to paragraph (d)(1). The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to their external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(3) No facility shall have a year 2000 Allocation [calculated pursuant to subdivision (d)] greater than the starting Allocation [calculated pursuant to subdivision (c)].

(4) If the sum of all RECLAIM facilities' year 2000 Allocations differs from the year 2000 projected inventory for these sources under the 1991 AQMP, the Executive Officer or designee will establish a percentage inventory adjustment factor that will be applied to adjust each facility's year 2000 Allocation. The inventory adjustment will not apply to RTCs generated from ERCs or external offsets.

(e) Allocations for the Year 2003

(1) The 2003 Allocations will be determined by the Executive Officer or designee applying a percentage inventory adjustment to reduce each facility's unadjusted year 2000 Allocation so that the sum of all RECLAIM facilities' 2003 Allocations will equal the 1991 AQMP projected inventory for RECLAIM sources for the year 2003, corrected

based on actual facility data reviewed for purposes of issuing Facility Permits and to reflect the highest year of actual Basin-wide economic activity for RECLAIM sources considered as a whole during the years 1987 through 1992.

(2) No facility shall have a 2003 Allocation (calculated pursuant this subdivision) greater than the year 2000 Allocation [calculated pursuant to subdivision (d)].

(f) Annual Allocations for NO_X and SOx and Adjustments to RTC Holdings

(1) Allocations for the years between 1994 and 2000, for RECLAIM NO_X and SO_X facilities shall be determined by a straight line rate of reduction between the starting Allocation and the year 2000 Allocation. For the years 2001 and 2002, the Allocations shall be determined by a straight line rate of reduction between the year 2000 and year 2003 Allocations. NOx Allocations for 2004, 2005, and 2006 and SOx Allocations for 2004 through 2012 are equal to the facility's 2003 Allocation, as determined pursuant to subdivision (e). NOx RTC Allocations and holdings subsequent to the year 2006 and SOx Allocations and holdings subsequent to the year 2012 shall be adjusted to the nearest pound as follows:

(A) The Executive Officer will adjust NOx RTC holdings, as of January 7, 2005 for compliance years 2007 and thereafter by multiplying the amount of RTC holdings by the following adjustment factors for the relevant compliance year, to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2007	0.883	0
2008	0.856	0.027
2009	0.829	0.054
2010	0.802	0.081
2011 ~~and after~~ through 2015	0.775	0.108

RTCs designated as non-tradable/non-usable pursuant to this subparagraph shall be held, but shall not be used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).

(B) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings by the following adjustment factors for the relevant compliance year, to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2016	0.925	0
2017	0.849	0.031
2018	0.774	0.063
2019	0.698	0.094
2020	0.623	0.126
2021	0.547	0.157
2022 and after	0.512	0.189

RTCs designated as non-tradable/non-usable pursuant to this subparagraph shall be held, but shall not be used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).

(~~B~~C) Commencing on January 1, 2008 with NOx RTC prices averaged from January 1, 2007 through December 31, 2007, the Executive Officer will calculate the 12-month rolling average RTC price for all trades for the current compliance year. The Executive Officer will update the 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(~~C~~D) ~~Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(A), i~~In the event that the NOx RTC prices exceed $15,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(~~B~~C), the Executive Officer will report to the Governing Board. Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(B) and ~~I~~if the Governing Board finds that the 12-month rolling average RTC price exceeds $15,000 per ton, then the incremental NOx reductions as specified in subparagraph (f)(1)(~~D~~E) shall be converted to Tradable/Usable NOx RTCs upon Governing

Board concurrence. The Executive Officer's report to the Board will be made at a public hearing at the earliest possible regularly scheduled Board Meeting, but no more than 60 days from Executive Officer determination.

(~~D~~E) The incremental NOx RTCs restored shall be the difference between the Non-tradable/Non-usable Adjustment Factors, as specified in subparagraph ~~(f)(1)(A)~~(f)(1)(B), of the current compliance year and the most recent prior year the adjustment factor was implemented.

(~~E~~F) RTC conversion pursuant to subparagraph (f)(1)(~~C~~D) shall~~-~~ only occur in the compliance year in which Cycle 1 facilities are operating.

(~~F~~G) Notwithstanding the adjustment factors required pursuant to subparagraph ~~(f)(1)(A)~~ (f)(1)(B), beginning with the following December and each year thereafter that the Governing Board finds the $15,000 per ton NOx RTC price is exceeded pursuant to subparagraph (f)(1)(~~C~~D), the Executive Officer will publish the applicable adjustment factors for the next compliance year beginning January 1. The adjustment factors will be published at a public hearing during a regularly scheduled Board Meeting. The adjustment factors will be determined as follows:

(i) If the 12-month rolling average falls below $15,000 per ton for at least 6 consecutive months, then the emission adjustment factors for the following compliance year shall equal the next more stringent adjustment factors listed in subparagraph ~~(f)(1)(A)~~ (f)(1)(B) than the factors currently in effect; otherwise;

(ii) The next compliance year adjustment factors shall equal the compliance year adjustment factors currently in place.

The Executive Officer need no longer comply with the annual public hearing requirement once the adjustment factors for the 2022~~10~~ compliance year have been implemented for a 12-month period.

(~~G~~H) The NOx RTC adjustment factors for compliance years 20~~08~~19 through 20~~10~~21 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022~~11~~ NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year.

(~~H~~I) NOx Allocations for facilities that enter RECLAIM after January 7, 2005 for compliance years 2007 and after shall be determined by applying the Tradable/Usable and Non-tradable/Non-usable NOx RTC Adjustment Factors under subparagraph (f)(1)(A) to the facility's Compliance Year 2006 Allocation and under subparagraph (f)(1)(B) to the facility's Compliance Year 2015 Allocation.

(~~I~~J) SOx RTC Holdings as of November 5, 2010, for compliance years 2013 and after shall be adjusted to achieve an overall reduction in the following amounts:

Compliance Year	Minimum emission reductions (lbs.)
2013	2,190,000
2014	2,920,000
2015	2,920,000
2016	2,920,000
2017	3,650,000
2018	3,650,000
2019 and after	4,161,000

(~~J~~K) The Executive Officer shall determine Tradable/usable SOx RTC Adjustment Factors for each compliance years after 2012 as follows:

$$F_{\text{compliance year i}} = 1 - [Xi / (Ai + Bi + Ci)]$$

Where:

$F_{\text{compliance year i}}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year i starting with 2013

A_i = Total SOx RTCs for compliance year i held as of November ~~11~~5, 2010, by all RTC holders, except those listed in Table 5

B_i = Total SOx RTCs for compliance year i credited to any facilities listed in Table 5 between August 29, 2009 and ~~(rule adoption date)~~November 5, 2010, and not includes in C_i

C_i = Total SOx RTCs held as of (rule adoption date) by facilities listed in Table 5 for compliance year i in excess of allocations as determined pursuant to subdivision (e).

X_i = Amount to be reduced for compliance year i starting with 2013 as listed in subparagraph (f)(1)(~~I~~J).

(~~K~~L) The Executive Officer shall determine Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2017 through 2019 as follows:

$$N_{\text{compliance year j}} = F_{\text{compliance year 2016}} - F_{\text{compliance year j}}$$

Where:

$N_{\text{compliance year j}}$ = Non-tradable/Non-usable SOx RTC Adjustment Factor for compliance year j

$F_{\text{compliance year j}}$ = Tradable/Usable SOx RTC Adjustment Factor for compliance year j as determined pursuant to subparagraph (f)(1)(~~J~~K)

j = 2017 through 2019

Fcompliance year 2016 = Tradable/usable SOx RTC Adjustment Factor for compliance year 2016 as determined pursuant to subparagraph (f)(1)(~~J~~K)

Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2013, 2014, 2020, and all years after 2020 shall be 0.0.

(~~L~~M) The Executive Officer shall adjust the SOx RTC holdings as of November 5, 2010, for compliance years 2013 and after as follows:

(i) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{\text{compliance year i}}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{\text{compliance year j}}$) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~N) to SOx RTC holdings held by any RTC holder except those listed in Table 5;

(ii) Apply no adjustment to SOx RTC holdings that are held as of August 29, 2009 by a facility listed in Table 5, and that are less than or equal to the facility's allocations as determined pursuant to subdivision (e), and that were not credited between August 29, 2009 and November 5, 2010;

(iii) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~N) to any SOx RTC holding as of ~~(~~November 5, 2010~~)~~, that is held by a facility that is listed in Table 5, and that is over the facility's allocations as determined pursuant to subdivision (e); and

(iv) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~N) to any SOx RTC holding that was acquired between August 29, 2009 and November 5, 2010, by a facility that is listed in Table 5.

No SOx RTC holding shall be subject to the SOx RTC adjustments as published under subparagraph (f)(1)(~~M~~N) more than once.

(~~M~~N) The Executive Officer shall publish the SOx RTC Adjustment Factors determined according to subparagraphs (f)(1)(~~J~~K) and (f)(1)(~~K~~L) within 30 days after November 5, 2010.

(~~N~~O) Commencing on January 1, 2017 and ending on February 1, 2020, the Executive Officer will calculate the 12-month rolling average SOx RTC price for all trades during the preceding 12 months for the current compliance year. The Executive Officer will update the 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(~~O~~P) In the event that the SOx RTC prices exceed $50,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(~~N~~O), the Executive Officer will report to the Governing Board at a duly noticed public hearing to be held no more than 60 days from Executive Officer determination. The Executive Officer will announce that determination on the SCAQMD website. At the public hearing, the Governing Board will decide whether or not to convert any portion of the Non-tradable/Non-usable RTCs, as determined pursuant to subparagraphs (f)(1)(~~K~~L) and (f)(1)(~~L~~M), and how much to convert if any, to Tradable/Usable RTCs. The portion of Non-tradable/Non-usable RTCs available for conversion to Tradable/Usable RTCs shall not include any portion of Non-tradable/Non-usable RTCs that are designated for previous compliance years and has not already been converted by the Governing Board, or that has been otherwise included in the State Implementation Plan pursuant to subparagraph (f)(1)(~~P~~Q).

(~~P~~Q) The Executive Officer will not submit the emission reductions obtained through subparagraph (f)(1)(~~I~~J) for compliance years 2017 through 2019 for inclusion into the State Implementation Plan until the adjustments for the RTC Holdings have been in effect for one full compliance year.

(~~Q~~R) SOx Allocations for compliance years 2013 and after, for facilities that enter RECLAIM after November 5, 2010, and for basic equipment listed in Table 4 shall be determined according to the BARCT level listed in Table 4 or the permitted emission limits, whichever is lower.

(2) New facilities initially totally permitted, on and after October 15, 1993, but prior to January 7, 2005, and entering the RECLAIM program after January 7, 2005 shall not have a rate of reduction until 2001. Reductions from 2001 to 2003, inclusive, shall be implemented pursuant to subdivision (e). New facilities initially totally permitted on or after January 7, 2005 using external offsets shall have a rate of reduction for such offsets pursuant to subparagraph (c)(5)(C). New facilities initially totally permitted on or after January 7, 2005 using RTCs shall have no rate of reduction for such RTCs, provided that RTCs obtained have been adjusted according to paragraph (f)(1), as applicable. The Facility Permit for such facilities will require the Facility Permit holder to, at the commencement of each compliance year, hold RTCs equal to the amount of RTCs provided as offsets pursuant to Rule 2005.

(3) Increases to Allocations for permits issued for Clean Fuel adjustments pursuant to paragraph (c)(12), shall be added to each year's Allocation.

(g) High Employment/Low Emissions (HILO) Facility

The Executive Officer or designee will establish a HILO bank funded with the following maximum total annual emission Allocations:

(1) 91 tons per year of NO_X

(2) 91 tons per year of So_X

(3) After January 1, 1997, new facilities may apply to the HILO bank in order to obtain non-tradable RTCs. Requests will be processed on a first-come, first-served basis, pending qualification.

(4) When credits are available, annual Allocations will be granted for the year of application and all subsequent years.

(5) HILO facilities receiving such Allocations from the HILO bank must verify their HILO status on an annual basis through their APEP report.

(6) Failure to qualify will result in all subsequent years' credits being returned to the HILO bank.

(7) Facilities failing to qualify for the HILO bank Allocations may reapply at any time during the next or subsequent compliance year when credits are available.

(h) Non-Tradable Allocation Credits

(1) Any existing RECLAIM facility with reported emissions pursuant to Rule 301 - Permit Fees, in either 1987, 1988, or 1993, greater than its starting Allocation, shall be assigned non-tradable credits for the first three years of the program which shall be determined according to the following methodology:

Non-tradable credit for NO_X and SO_X:

Year 1 = $(\Sigma [A \text{ X } B_1])$ - 1994 Allocation;

Where:

A	=	the throughput for each NO_X or SO_X source or process unit in the facility from the single maximum throughput year from 1987, 1988, or 1993; and
B_1	=	the applicable starting emission factor, as specified in Table 1 or Table 2.
Year 2	=	Year 1 non-tradable credits X 0.667
Year 3	=	Year 1 non-tradable credits X 0.333
Year 4 and subsequent years	=	Zero non-tradable credit.

(2) The use of non-tradable credits shall be subject to the following requirements:

(A) Non-tradable credits may only be used for an increase in throughput over that used to determine the facility's starting Allocation. Non-tradable credits may not be used for emissions increases associated with equipment modifications, change in feedstock or raw materials, or any other changes except increases in throughput. The Executive Officer or designee may impose Facility Permit conditions necessary to ensure compliance with this subparagraph.

(B) The use of activated non-tradable credits shall be subject to a non-tradable RTC mitigation fee, as specified in Rule 301 subdivision (n).

(C) In order to utilize non-tradable credits, the Facility Permit holder shall submit a request to the Executive Officer or designee in writing, including a demonstration that the use of the non-tradable credits complies with all requirements of this paragraph, pay any fees required pursuant to Rule 301 - Fees, and have received written approval from the Executive Officer or designee for their use. The Executive Officer or designee shall deny the request unless the Facility Permit holder demonstrates compliance with all requirements of this paragraph. The Executive Officer or designee shall, in writing, approve or deny the request within three business days of submittal of a complete request and notify the Facility Permit holder of the decision. If the request is denied, the Executive Officer or designee will refund the mitigation fee.

(D) In the event that a facility transfers any RTCs for the year in which non-tradable credits have been issued, the non-tradable credit Allocation shall be invalid, and is no longer available to the facility.

(i) RTC Reduction Exemption

(1) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraph (f)(1)(~~A~~B) with the exception of RTC holdings as of ~~January 7, 2005 for compliance year 2007~~ (Date of Amendment) for compliance year 2016 and thereafter in excess of the initial allocation. For the purposes of this rule, initial allocation refers to the RTCs issued by the District to a facility upon entering the RECLAIM program. The

application shall contain sufficient data to demonstrate to the satisfaction of the Executive Officer that the facility meets the following criteria:

(A) the facility has been in the program since the start of RECLAIM, or existed prior to 1994, but subsequently entered RECLAIM pursuant to Rule 2001 because facility emissions exceeded 4 tons per year;

(B) at least 99 percent of the facility's emissions reported for ~~the most recent completed c~~Compliance ~~y~~Year 2013 ~~prior to the date of filing an application~~ is from equipment not listed in Table 3 or Table 6 and the achieved emission rates for each and every piece of equipment at the facility is less than or equal to the 2000 (Tier I) Ending Emission Factor listed in Table 1 or the emission factor listed in Table 3, whichever is lower, for the corresponding equipment type;

(C) RTCs that were part of the total initial allocation for the facility have never been transferred or sold by the facility for Compliance Year~~year~~ 2016~~07~~ or later~~ compliance years~~; and

(D) the cumulative NOx compliance costs incurred by the facility up to the submittal date of the application as specified in paragraph (i)(3) to comply with the RECLAIM Allocation as required under Rule 2004(b) and (d)(1) exceed the compliance costs that otherwise would have occurred to meet and maintain emission limits specified in Table 1 or 3, whichever is lower, for each and every piece of equipment at the facility. The compliance costs shall be based on the following parameters:

(i) cost of controlling emissions using the parameters and procedures for determining total direct and indirect capital investment and total annual costs as specified in the most recent edition of the Control Cost Manual published by the U.S. EPA Office of Air Quality and Planning Standards, excluding control costs for any equipment listed in Table 3 or Table 6, if any;

(ii) realized and anticipated revenues and expenditures of the Facility Permit holder resulting from buying and selling any RTCs that are or were held by the facility where the contract of sale or purchase was executed prior to the date of application for exemption pursuant to paragraph (i)(1);

(iii) costs associated with compliance with the New Source Review provisions of Rule 2005, Rule 2012(c), or other applicable state or federal requirements shall not be included;

(iv) costs that result only in improving process efficiency or product quality, costs of projects that were initiated before the date the facility was subject to RECLAIM requirements, or legal costs or any other costs that do not directly reduce NOx emissions shall not be included; and

(v) any cost savings that resulted in implementing any NOx emissions strategy, such as fuel savings, increased production or sale; or

(2) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraph (f)(1)(~~A~~B) for the initial allocations portion of a facility's RTC holdings provided that the facility meets all of the following:

(A) The facility's starting and year 2000 Allocations were calculated using the same emission factors that are equal to or lower than the 2000 (Tier 1) emission factors listed in Table 1;

(B) Emission rate achieved for each source at the facility is less than or equal to the emission factors listed in Table 3 for the corresponding equipment type; and

(C) RTCs for ~~2007~~ 2016 or later compliance years for the facility have never been transferred or sold.

(3) A facility shall submit the applications specified pursuant to paragraphs (i)(1) or (i)(2) no later than ~~July 7, 2005~~ six months after adoption of rule amendment ~~or between January 1 and March 31, 2006~~, pay the appropriate evaluation fee pursuant to Rule 306, and accept enforceable permit conditions to ensure compliance with the provisions of this subdivision, in order for the Executive Officer to approve the exemption. If approved, the facility's initial RTC allocation shall be designated as

non-tradable and additional RTCs purchased above the initial allocation shall be subject to the RTC adjustments specified in subparagraph (f)(1)(~~A~~B), as appropriate. The Executive Officer shall deny an application that is not filed within the time periods specified in this paragraph, lacks any information specified under paragraph (i)(7), or fails to demonstrate that it meets the requirements in paragraphs (i)(1) or (i)(2).

(4) Upon approval the exemption shall:

(A) be limited to the adjustment factors specified in subparagraph (f)(1)(~~A~~B);

(B) begin the next compliance year following the exemption approval; and

(C) not apply to reductions resulting from future periodic BARCT review.

(5) RTC adjustments exempted pursuant to this subdivision shall be distributed proportionally among the remainder of the RTC holders and implemented two years from the compliance year of the applicable exemption and are subject to applicable paragraph (f)(1) provisions. Public notification of the distributed reductions shall occur at least one year prior to implementation.

(6) A Facility Permit holder has the right to appeal the denial of the exemption application to the Hearing Board in the same manner as a permit denial as specified in Health and Safety Code Section 42302.

(7) An application submitted to request an exemption from the RTCs reduction pursuant to paragraphs (i)(1) or (i)(2) shall include the following information.

(A) Detailed description of each project and itemized listing of how it relates to meeting the RECLAIM reduction requirements;

(B) Date of start and completion of each project listed in (A);

(C) Detailed calculations or emissions data demonstrating NOx emission reductions resulting from each project or combination of projects directly resulting in reductions. The emission levels achieved shall be based on actual CEMS data or source tests results;

(D) Itemized revenue and expenditures for each RTC trading activity since participation in the RECLAIM program;

(E) Itemized costs for each project and corresponding receipts or other equivalent documentation as approved by the Executive Officer for such expenditures; and

(F) Cost savings resulting from each project(s) (e.g. fuel savings, improved productivity, increased sales, etc.) and documentation of the values of such savings.

(8) A facility qualifying for exemption shall report as part of its Annual Permit Emission Program (APEP) report, submitted pursuant to Rule 2004(b)(4), whether or not emissions from equipment listed in Tables 3 and 6, if any, remain less than or equal to 1 percent of the total facility emissions on an annual basis for the duration of the exemption. If the emissions exceed 1 percent, the facility shall be in violation of the rule for each and every day of the compliance year and the Executive Officer shall reduce the facility's initial allocation for the next compliance year to the emissions level specified for that year pursuant to subparagraph (f)(1)(~~A~~B).

(9) A facility applying for exemption shall have 1 percent of its initial allocations subject to the requirements pursuant to subparagraph (f)(1)(~~A~~B).

(10) Non-tradable RTC allocations designated pursuant to paragraph (i)(3) shall become tradable in the event the facility permanently ceases to operate.

Table 1

RECLAIM NO_X Emission Factors

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Afterburner (Direct Flame and Catalytic)	Natural Gas	mmcf	130.000	39.000
Afterburner (Direct Flame and Catalytic)	LPG, Propane, Butane	1000 Gal	RV	3.840
Afterburner (Direct Flame and Catalytic)	Diesel	1000 Gal	RV	5.700
Agr Chem-Nitric Acid	Process-Absrbr Tailgas/Nw	tons pure acid produced	RV	1.440
Agricultural Chem - Ammonia	Process	tons produced	RV	1.650
Air Ground Turbines	Air Ground Turbines	(unknown process units)	RV	1.860
Ammonia Plant	Neutralizer Fert, Ammon Nit	tons produced	RV	2.500
Asphalt Heater, Concrete	Natural Gas	mmcf	130.000	65.000
Asphalt Heater, Concrete	Fuel Oil	1000 gals	RV	9.500
Asphalt Heater, Concrete	LPG	1000 gals	RV	6.400
Boiler, Heater R1109 (Petr Refin)	Natural Gas	mmbtu	0.100	0.030
Boiler, Heater R1109 (Petr Refin)	Fuel Oil	mmbtu	0.100	0.030
Boiler, Heater R1146 (Petr Refin)	Natural Gas	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Fuel Oil	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Refinery Gas	mmbtu	0.045	0.045
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Natural Gas	mmcf	49.180	47.570
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	LPG, Propane, Butane	1000 gals	4.400	4.260
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Diesel Light Dist. (0.05% S)	1000 gals	6.420	6.210
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Refinery Gas	mmcf	51.520	49.840
Boilers, Heaters, Steam Gens	Bituminous Coal	tons burned	RV	4.800
Boiler, Heater, Steam Gen (Rule 1146.1)	Natural Gas	mmcf	130.000	39.460
Boiler, Heater, Steam Gen (Rule 1146.1)	Refinery Gas	mmcf	RV	41.340

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boiler, Heater, Steam Gen (Rule 1146.1)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (Rule 1146.1)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater, Steam Gen (Rule 1146)	Natural Gas	mmcf	47.750	47.750
Boiler, Heater, Steam Gen (Rule 1146)	Refinery Gas	mmcf	50.030	50.030
Boiler, Heater, Steam Gen (Rule 1146)	LPG, Propane, Butane	1000 gallons	4.280	4.280
Boiler, Heater, Steam Gen (Rule 1146)	Diesel Light Dist (0.05%)	1000 gallons	6.230	6.230
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Natural Gas	mmcf	RV	47.750
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Refinery Gas	mmcf	RV	50.030
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	4.280
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	6.230
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Natural Gas	mmcf	RV	39.460
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Refinery Gas	mmcf	RV	41.340
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater R1109 (Petr Refin)	Refinery Gas	mmbtu	0.100	0.030
Boilers, Heaters, Steam Gens, (Petr Refin)	Natural Gas	mmcf	105.000	31.500
Boilers, Heaters, Steam Gens, (Petr Refin)	Refinery Gas	mmcf	110.000	33.000
Boilers, Heaters, Steam Gens, Unpermitted	Natural Gas	mmcf	130.000	32.500
Boilers, Heaters, Steam Gens, Unpermitted	LPG, Propane, Butane	1000 gallons	RV	3.200
Boilers, Heaters, Steam Gens ****	Natural Gas	mmcf	38.460	38.460

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boilers, Heaters, Steam Gens ****	Refinery Gas	mmbtu	0.035	0.035
Boilers, Heaters, Steam Gens ****	LPG, Propane, Butane	1000 gallons	3.55	3.55
Boilers, Heaters, Steam Gens ****	Diesel Light Dist (0.05%), Fuel Oil No. 2	mmbtu	0.03847	0.03847
Boilers, Heaters, Steam Gens, Unpermitted	Diesel Light Dist (0.05%)	1000 gallons	RV	4.750
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	1.660
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	2.090
Cement Kilns	Natural Gas	mmcf	130.000	19.500
Cement Kilns	Diesel Light Dist. (0.05% S)	1000 gals	RV	2.850
Cement Kilns	Kilns-Dry Process	tons cement produced	RV	0.750
Cement Kilns	Bituminous Coal	tons burned	RV	4.800
Cement Kilns	Tons Clinker	tons clinker	RV	2.73***
Ceramic and Brick Kilns (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Ceramic and Brick Kilns (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Ceramic and Brick Kilns (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Ceramic Clay Mfg	Drying	tons input to process	RV	1.114
CO Boiler	Refinery Gas	mmbtu		0.030
Cogen, Industr	Coke	tons burned	RV	3.682
Electric Generation, Commercial Institutional Boiler	Distillate Oil	1000 gallons	6.420	6.210
Composite Internal Combustion	Waste Fuel Oil	1000 gals burned	RV	31.340
Curing and Drying Ovens	Natural Gas	mmcf	130.000	32.500

* RV = Reported Value
** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.
*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.
**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Curing and Drying Ovens	LPG, Propane, Butane	1000 gals	RV	3.200
Delacquering Furnace	Natural Gas	mmcf	182.2***	182.2***
Fiberglass	Textile-Type Fibr	tons of material processed	RV	1.860
Fluid Catalytic Cracking Unit	Fresh Feed	1000 BBLS fresh feed	RV	RV*0.3 ***
Fluid Catalytic Cracking Unit with Urea Injection	Fresh Feed	1000 BBLS fresh feed	RV	(RV*0.3) / (1-control efficiency) ***
Fugitive Emission	Not Classified	tons product	RV	0.087
Furnace Process	Carbon Black	tons produced	RV	38.850
Furnace Suppressor	Furnace Suppressor	unknown	RV	0.800
Glass Fiber Furnace	Mineral Products	tons product produced	RV	4.000
Glass Melting Furnace	Flat Glass	tons of glass pulled	RV	4.000
Glass Melting Furnace	Tableware Glass	tons of glass pulled	RV	5.680
Glass Melting Furnaces	Container Glass	tons of glass produced	4.000	1.2***
ICEs****	All Fuels		Equivalent to permitted BACT limit	Equivalent to permitted BACT limit
ICEs, Permitted (Rule 1110.1 and 1110.2)	Natural Gas	mmcf	2192.450	217.360
ICEs Permitted (Rule 1110.2)	Natural Gas	mmcf	RV	217.360
ICEs, Permitted (Rule 1110.1 and 1110.2)	LPG, Propane, Butane	1000 gals	RV	19.460
ICEs, Permitted (Rule 1110.1 and 1110.2)	Gasoline	1000 gals	RV	20.130
ICEs, Permitted (Rule 1110.1 and 1110.2)	Diesel Oil	1000 gals	RV	31.340
ICEs, Exempted per Rule 1110.2	All Fuels		RV	RV
ICEs, Exempted per Rule 1110.2 and subject to Rule 1110.1	All Fuels		RV	RV
ICEs, Unpermitted	All Fuels		RV	RV
In Process Fuel	Coke	tons burned	RV	24.593
Incinerators	Natural Gas	mmcf	130.000	104.000
Industrial	Propane	1000 gallons	RV	20.890
Industrial	Gasoline	1000 gallons	RV	21.620

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Industrial	Dist.Oil/Diesel	1000 gallons	RV	33.650
Inorganic Chemicals, H2SO4 Chamber	General	tons pure acid produced	RV	0.266
Inorganic Chemicals, H2SO4 Contact	Absrbr 98.0% Conv	tons 100% H2S04	RV	0.376
Iron/Steel Foundry	Steel Foundry, Elec Arc Furn	tons metal processed	RV	0.045
Metal Heat Treating Furnace	Natural Gas	mmcf	130.000	104.000
Metal Heat Treating Furnace	Diesel Light Distillate (.05%)	1000 gallons	RV	15.200
Metal Heat Treating Furnace	LPG	1000 gallons	RV	10.240
Metal Forging Furnace (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Metal Forging Furnace (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Metal Forging Furnace (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Metal Melting Furnaces	Natural Gas	mmcf	130.000	65.000
Metal Melting Furnaces	LPG, Propane, Butane	1000 gals	RV	6.400
Miscellaneous		bbls-processed	RV	1.240
Natural Gas Production	Not Classified	mmcf gas	RV	6.320
Nonmetallic Mineral	Sand/Gravel	tons product	RV	0.030
NSPS	Refinery Gas	mmbtu	RV	0.030
Other BACT Heater (24F-1)	Natural Gas	mmcf	RV	RV
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV
Ovens, Kilns, Calciners, Dryers, Furnaces**	Natural Gas	mmcf	130.000	65.000
Ovens, Kilns, Calciners, Dryers, Furnaces**	Diesel Light Dist. (0.05% S)	1000 gals	RV	9.500
Paint Mfg, Solvent Loss	Mixing/Blending	tons solvent	RV	45.600
Petroleum Refining	Asphalt Blowing	tons of asphalt produced	RV	45.600
Petroleum Refining, Calciner	Petroleum Coke	Calcined Coke	RV	0.971***
Plastics Prodn	Polyester Resins	tons product	RV	106.500
Pot Furnace	Lead Battery	lbs Niter	0.077***	0.062***
Process Specific	ID# 012183	(unknown process units)	RV	240.000
Process Specific	SCC 30500311	tons produced	RV	0.140

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Process Specific	ID 14944	(unknown process units)	RV	0.512
SCC 39090003			RV	170.400
Sec. Aluminum	Sweating Furnace	tons produced	RV	0.300
Sec. Aluminum	Smelting Furnace	tons metal produced	RV	0.323
Sec. Aluminum	Annealing Furnace	mmcf	130.000	65.000
Sec. Aluminum	Boring Dryer	tons produced	RV	0.057
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.110
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.060
Sodium Silicate Furnace	Water Glass	Tons Glass Pulled	RV	6.400
Steel Hot Plate Furnace	Natural Gas	mmcf	213.000	106.500
Steel Hot Plate Furnace	Diesel Light Distillate (.05%)	1000 gallons	31.131	10.486
Steel Hot Plate Furnace	LPG, Propane, Butane	1000 gallons	20.970	10.486
Surface Coal Mine	Haul Road	tons coal	RV	62.140
Tail Gas Unit		hours of operation	RV	RV
Turbines	Butane	1000 Gallons	RV	5.700
Turbines	Diesel Oil	1000 gals	RV	8.814
Turbines	Refinery Gas	mmcf	RV	62.275
Turbines	Natural Gas	mmcf	RV	61.450
Turbines (micro-)	Natural Gas	mmcf	54.4	54.4
Turbines - Peaking Unit	Natural Gas	mmcf	RV	RV
Turbines - Peaking Unit	Dist. Oil/Diesel	1000 gallons	RV	RV
Utility Boiler	Digester/Landfill Gas	mmcf	52.350	10.080
Turbine	Natural Gas	mmcf	RV	61.450
Turbine	Fuel Oil	1000 gallons	RV	8.810
Turbine	Dist.Oil/Diesel	1000 gallons	RV	3.000
Utility Boiler Burbank	Natural Gas	mmcf	148.670	17.200
Utility Boiler Burbank	Residual Oil	1000 gallons	20.170	2.330
Utility Boiler, Glendale	Natural Gas	mmcf	140.430	16.000
Utility Boiler, Glendale	Residual Oil	1000 gallons	20.160	2.290
Utility Boiler, LADWP	Natural Gas	mmcf	86.560	15.830
Utility Boiler, LADWP	Residual Oil	1000 gallons	12.370	2.260
Utility Boiler, LADWP	Digester Gas	mmcf	52.350	10.080
Utility Boiler, LADWP	Landfill Gas	mmcf	37.760	6.910
Utility Boiler, Pasadena	Natural Gas	mmcf	195.640	18.500
Utility Boiler, Pasadena	Residual Oil	1000 gallons	28.290	2.670
Utility Boiler, SCE	Natural Gas	mmcf	74.860	15.600
Utility Boiler, SCE	Residual Oil	1000 gallons	10.750	2.240

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Table 2

RECLAIM SO_X Emission Factors

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Air Blown Asphalt		hours of operation	RV	RV
Asphalt Concrete	Cold Ag Handling	tons produced	RV	0.032
Calciner	Petroleum Coke	Calcined Coke	RV	0.000
Catalyst Regeneration		hours of operation	RV	RV
Cement Kiln	Distillate Oil	1000 gallons	RV	RV
Cement Mfg	Kilns, Dry Process	tons produced	RV	RV
Claus Unit		pounds	RV	RV
Cogen	Coke	pounds per ton	RV	RV
Non Fuel Use		hours of operation	RV	RV
External Combustion Equipment / Incinerator	Natural Gas	mmcf	RV	0.830
External Combustion Equip/Incinerator	LPG, Propane, Butane	1000 gallons	RV	4.600
External Combustion Equip/Incinerator	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	5.600
External Combustion Equip/Incinerator	Residual Oil	1000 gallons	8.00	6.400
External Combustion Equip/Incinerator	Refinery Gas	mmcf	RV	6.760
Fiberglass	Recuperative Furn, Textile-Type Fiber	tons produced	RV	2.145
Fluid Catalytic Cracking Units		1000 bbls refinery feed	RV	13.700
Glass Mfg, Forming/Fin	Container Glass		RV	RV
Grain Milling	Flour Mill	tons Grain Processed	RV	RV
ICEs	Natural Gas	mmcf	RV	0.600
ICEs	LPG, Propane, Butane	1000 gallons	RV	0.350
ICEs	Gasoline	1000 gallons	RV	4.240
ICEs	Diesel Oil	1000 gallons	6.24	4.990
Industrial	Cogeneration, Bituminous Coal	tons produced	RV	RV
Industrial (scc 10200804)	Cogeneration, Coke	tons produced	RV	RV
Inorganic Chemcals	General, H2SO4 Chamber	tons produced	RV	RV
Inorganic Chemcals	Absrbr 98.0% Conv, H2SO4 Contact	tons produced	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Inprocess Fuel	Cement Kiln/Dryer, Bituminous Coal	tons produced	RV	RV
Iron/Steel Foundry	Cupola, Gray Iron Foundry	tons produced	RV	0.720
Melting Furnace, Container Glass		tons produced	RV	RV
Mericher Alkyd Feed		hours of operation	RV	RV
Miscellaneous	Not Classified	tons produced	RV	0.080
Miscellaneous	Not Classified	tons produced	RV	0.399
Natural Gas Production	Not Classified	mmcf	RV	527.641
Organic Chemical (scc 30100601)		tons produced	RV	RV
Petroleum Refining (scc30600602)	Column Condenser		RV	1.557
Petroleum Refining (scc30600603)	Column Condenser		RV	1.176
Refinery Process Heaters	LPG fired	1000 gal	RV	2.259
Pot Furnace	Lead Battery	lbs Sulfur	0.133***	0.106***
Sec. Lead	Reverberatory, Smelting Furnace	tons produced	RV	RV
Sec. Lead	Smelting Furnace, Fugitiv	tons produced	RV	0.648
Sour Water Oxidizer		hours of operation	RV	RV
Sulfur Loading		1000 bbls	RV	RV
Sour Water Oxidizer		1000 bbls fresh feed	RV	RV
Sour Water Coker		1000 bbls fresh feed	RV	RV
Sodium Silicate Furnace		tons of glass pulled	RV	RV
Sulfur Plant		hours of operation	RV	RV
Tail gas unit		hours of operation	RV	RV
Turbines	Refinery Gas	mmcf	RV	6.760
Turbines	Natural Gas	mmcf	RV	0.600
Turbines	Diesel Oil	1000 gal	6.24	0.080
Turbines	Residual Oil	1000 gallons	8.00	0.090
Utility Boilers	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	0.080
Utility Boilers	Residual Oil	1000 gallons	8.00	0.090
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Table 3

RECLAIM NO_X 2011 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Asphalt Heater, Concrete	0.036 lb/mmbtu (30 ppm)
Boiler, Heater R1109 (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boilers, Heaters, Steam Gens, (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boiler, Heater, Steam Gen (Rule 1146.1) 2-20 mmbtu/hr	0.015 lb/mmbtu (12 ppm)
Boiler, Heater, Steam Gen (Rule 1146) >20 mmbtu/hr	0.010 lb/mmbtu (9 ppm)
CO Boiler	85% Reduction
Delacquering Furnace	0.036 lb/mmbtu (30 ppm)
Fluid Catalytic Cracking Unit	85% Reduction
Iron/Steel Foundry	0.055 lb/mmbtu (45 ppm)
Metal Heat Treating Furnace	0.055 lb/mmbtu (45 ppm)
Metal Forging Furnace (Preheated Combustion Air)	0.055 lb/mmbtu (45 ppm)
Metal Melting Furnaces	0.055 lb/mmbtu (45 ppm)
Other Heater (24F-1)	0.036 lb/mmbtu (30 ppm)
Ovens, Kilns, Calciners, Dryers, Furnaces	0.036 lb/mmbtu (30 ppm)
Petroleum Refining, Calciner	0.036 lb/mmbtu (30 ppm)
Sec. Aluminum	0.055 lb/mmbtu (45 ppm)
Sec. Lead	0.055 lb/mmbtu (45 ppm)
Steel Hot Plate Furnace	0.055 lb/mmbtu (45 ppm)
Utility Boiler	0.008 lb/mmbtu (7 ppm)

Table 4
RECLAIM SOx Tier III Emission Standards

Basic Equipment	BARCT Emission Standard
Calciner, Petroleum Coke	10 ppmv (0.11 lbs/ton coke)
Cement Kiln	5 ppmv (0.04 lbs/ton clinker)
Coal-Fired Boiler	5 ppmv (95% reduction)
Container Glass Melting Furnace	5 ppmv (0.03 lbs/ton glass)
Diesel Combustion	15 ppmv as required under Rule 431.2
Fluid Catalytic Cracking Unit	5 ppmv (3.25 lbs/thousand barrels feed)
Refinery Boiler/Heater	40 ppmv (6.76 lbs/mmscf~~t~~)
Sulfur Recovery Units/Tail Gas	5 ppmv for combusted tail gas (5.28 lbs/hour)
Sulfuric Acid Manufacturing	10 ppmv (0.14 lbs/ton acid produced)

Table 5
List of SOx RECLAIM Facilities Referenced in Paragraph (f)(1)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES HUNTINGTON BEACH, LLC*	115389
AIR LIQUIDE LARGE INDUSTRIES U.S., LP	148236
ANHEUSER-BUSCH INC., (LA BREWERY)	16642
CALMAT CO	119104
CENCO REFINING CO	800373
EDGINGTON OIL COMPANY	800264
EQUILON ENTER. LLC, SHELL OIL PROD. US	800372
EXIDE TECHNOLOGIES	124838
INEOS POLYPROPYLENE LLC	124808
KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	21887
LUNDAY-THAGARD COMPANY	800080
OWENS CORNING ROOFING AND ASPHALT, LLC	35302
PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	45746
PARAMOUNT PETR CORP*	800183
QUEMETCO INC	8547
RIVERSIDE CEMENT CO	800182
TECHALLOY CO., INC.	14944
TESORO REFINING AND MARKETING CO*	151798
THE PQ CORP	11435
US GYPSUM CO	12185
WEST NEWPORT OIL CO	42775

* SOx RECLAIM facilities that have RTC Holdings larger than initial allocations as of August 29, 2009.

Table 6

RECLAIM NO_x 2021 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Boiler, Heater R1109 (Petr Refin) >40 mmbtu/hr	2 ppm
Cement Kilns	0.5 lbs per ton clinker
Fluid Catalytic Cracking Unit	2 ppm
Gas Turbines	2 ppm
Glass Melting Furnaces – Container Glass	80% reduction (0.24 lb/ton glass produced)
ICEs, Permitted (Rule 1110.2) (Non-OCS)	11 ppm @15%O_2 0.041 lb/MMBTU 43.05 lb/mmcf
Metal Heat Treating Furnace >150 mmbtu/hr	0.011 lb/mmbtu (9 ppm)
Petroleum Refining, Calciner	2 ppm
Sodium Silicate Furnace	80% reduction (1.28 lb/ton glass pulled)
SRU/Tail Gas Unit	95% reduction 2ppm

APPENDIX B

PROPOSED AMENDED RULE 2011 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF SULFUR (SOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

RULE 2011 PROTOCOL - ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. QUALITY CONTROL PROGRAM

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

Explain how each component of the CEMS shall be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that shall be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However, facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the SOx protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be given is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments during each day in which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, during each day that emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Test, record, and compute the calibration error of each SO_2 pollutant concentration monitor, fuel gas sulfur content monitor, if applicable, and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration or the fuel gas sulfur content has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration or the fuel gas sulfur content has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

i. Design Requirements for Calibration Error Testing of SO_x Concentration Monitors, the Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Design and equip each SO_x concentration monitor, fuel gas sulfur content monitor, and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor, fuel gas sulfur content and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for SO_x Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Measure the calibration error of each SO_2 concentration analyzer, fuel gas sulfur analyzer, and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking on all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the SO_x concentration monitors, the fuel gas sulfur content monitors, and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = Percentage calibration error based on the span range

R = Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Chapter 2, Subdivision B, Paragraph 1, Subparagraph c of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the SOx monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an SO_2 concentration monitor or a fuel gas sulfur content monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, dscfh, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the SO_X pollutant concentration monitor, flow monitoring system, and SOx emission rate measurement system is 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that only operates under a California Independent System Operator (Cal ISO) contract may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and a CGA is conducted and passed within the calendar quarter when the assessment is due.

~~a.~~e. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each $S0_2$ pollutant concentration monitor, fuel gas sulfur content monitor, stack gas volumetric flow rate measurement systems, and the $S0_2$ mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, and 12 and Attachment B of the Protocol for ~~Proposed~~ Rule 2011. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, and 12 and Attachment B (bias test) of the ~~Draft~~ Protocol for ~~Proposed~~ Rule 2011.

~~b.~~f. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor, a fuel gas sulfur content monitor, or the $S0_2$ emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

~~c.~~g. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

~~d.~~h. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.~~a~~e.; and

III. conducted an ~~alterative~~ alternative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.~~d~~h.iii.

If any of the requirements under Subclauses B.2.~~d~~h.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours~~.~~; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

APPENDIX C

PROPOSED AMENDED RULE 2012 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF NITROGEN (NOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

RULE 2012 PROTOCOL - ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

   Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

   Explain how each component of the CEMS will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

   Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

   Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that will be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the NO_x protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be performed is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments on each day during which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, on each day during which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors and O_2 Monitors

Test, record, and compute the calibration error of each NO_x pollutant concentration monitor and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Paragraph B.1.a.ii. of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales

i. Design Requirements for Calibration Error Testing of NO_x Concentration Monitors and O_2 Monitors

Design and equip each NO_x concentration monitor and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for NO_x Concentration Monitors and O_2 Monitors

Measure the calibration error of each NO_x concentration analyzer and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the NO_x concentration monitors and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R-A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = The percentage calibration error based on the span range

R = The reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = The actual monitoring system response to the calibration gas.

S = The span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation :

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the. transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Paragraph B.1.c.i. of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

i. Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the NO_x monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an NO_x concentration monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, DSCFH, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the NO_X pollutant concentration monitor, flow monitoring system, and NOx emission rate measurement system is 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that only operates under a California Independent System Operator (Cal ISO) contract may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and a CGA is conducted and passed within the calendar quarter when the assessment is due.

~~a.~~e. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each NO_X pollutant concentration monitor, stack gas volumetric flow rate measurement systems, and the NO_X mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraph 10, Chapter 2, Subdivision B, Paragraph 11, and Chapter 2, Subdivision B, Paragraph 12. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Paragraphs 2.B.10, 2.B.11, and 2.B.12.

~~b.~~f. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an NO_X pollutant concentration monitor or the NO_X emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

~~c.~~g. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

~~d.~~h. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.~~a~~e.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.~~d~~h.iii

If any of the requirements under Subclauses B.2.~~d~~h.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours ; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

APPENDIX G

COMMENT LETTERS RECEIVED ON THE NOP/IS AND RESPONSES TO COMMENTS

INTRODUCTION

A Notice of Preparation/Initial Study (NOP/IS) was released for a 57-day public review and comment period from December 5, 2014 to January 30, 2015 which identified the environmental topics of aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic, as potentially being significantly adversely affected by the project. The SCAQMD received eight comment letters regarding the preliminary analysis in the NOP/IS during the public comment period.

The comment letters have been numbered (see Table G-1 below) and individual comments within each letter have been bracketed and numbered. Following each comment letter is SCAQMD staff's responses to the individual comments.

Table G-1
List of Comment Letters Received Relative to the NOP/IS

Comment Letter	Commentator
#1	Baker Commodities
#2	Air Products
#3	CalPortland
#4	Los Angeles Department of Water and Power (LADWP)
#5	Charles F. Timms, Jr. on behalf of City of Burbank Department of Water and Power
#6	California Council for Environmental and Economic Balance (CCEEB) et al
#7	Paramount Petroleum
#8	Public Solar Power Coalition

Comment Letter #1

January 29, 2015

South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Attn: Barbara Radlein

Re: Comments on "Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)"

Ms. Radlein:

SCAQMD has recognized that a small percentage of facilities are responsible for a majority of NOx emissions in the South Coast air basin. These high-producing NOx facilities, owned by major corporations and utility companies, have the resources available to invest in the technologies outlined in the BARCT analysis and achieve substantial reductions in their NOx emissions. However, SCAQMD is proposing a shave of nearly half of all RECLAIM Trading Credits (RTCs) from both large and small facilities alike. Baker Commodities ("Baker") does not feel that small companies such as ours should be punished for the emissions of a select few large facilities. 1-1

Baker is not a major source of NOx amongst RECLAIM facilities, cannot achieve significant emission reductions by implementing any control technology, and does not have the resources available to invest in them. Moreover, at current RTC prices, purchasing additional RTCs to make up for a reduced allocation will place an equally onerous burden on Baker's operations. 1-2

The proposed RTC shave translates to a reduction of .015 potential tons of NOx per day for Baker's facility. If Baker were to invest in control technology, such as selective catalytic reduction (costing upwards of $1 million), we are likely to see an actual reduction of approximately .012 tons of NOx per day. In such scenario, Baker is looking at a figure that amounts to less than 0.5% of SCAQMD's 5 tons per day reduction target, per CMB-01. With the currently proposed amendments to Rule 2002 targeting a reduction greater than 5 tons per day, investment by Baker in such technology seems immaterial and like a poor return on the investment. 1-3

Baker requests that only those facilities that are significant contributors of NOx and have the potential for major reductions in their emissions, such as the top emitters that are the focus of the BARCT analysis, be subject to the currently proposed NOx RTC shave. 1-4

Sincerely,

Chris Hassler
Environmental Compliance Specialist, Baker Commodities

RESPONSES TO COMMENT LETTER #1
(Baker Commodities - January 29, 2015)

1-1 This comment points out that a small percentage of facilities are responsible for a majority of NOx emissions in the SCAB and these facilities have the resources to invest in the technologies outlined in the BARCT analysis in order to achieve NOx reductions. This comment also claims that a proposed shave of nearly half of all RTCs from both large and small facilities, would disproportionately punish small facilities, including the commentator's facility.

SCAQMD staff conducted a BARCT assessment of the NOx RECLAIM program which resulted in adjusting BARCT levels for both equipment and source categories in the refinery and non-refinery sectors. For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters rated greater than 40 mmBTU/hr, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal melting furnaces rated greater than 150 mmBTU/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for power plants. Overall, a total of 14 tpd of NOx RTC reductions from the current RTC holdings of 26.5 tpd is proposed. For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will only affect 65 facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 210 facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT was identified for the types of equipment and source categories at these facilities.

Tables 7 and 8 in PAR 2002 list the facilities that would have RTC adjustments. The commentor's facility is not included in either of these tables. This facility is included in the facilities for which there is not a proposed shave.

1-2 The commentator states that their facility is not a major source of NOx emissions among RECLAIM facilities, cannot achieve significant emission reductions by implementing any control technology, and does not have the resources to invest in control technology. This comment claims that the cost of purchasing RTCs will place an onerous burden on the commentator's facility operations.

This facility is considered a major source of NOx emissions because it is a Title V facility with NOx emissions that have ranged over the last decade from 7 to 13 tons per year. The commentator's facility is not included in the categories of facilities that have a proposed RTC reduction, see Tables 6 and 7 in PAR 2002. See also Response 1-1.

1-3 This comment claims that the proposed shave represents 0.015 tons per day NOx RTC reductions for the commentator's facility and if control technology such as SCR were installed at a cost of $1 million, the actual NOx emission reductions would be 0.012 tons per day which amounts to less than 0.5 percent of SCAQMD's NOx emission reduction goal of five tons per day.

The commentator's facility is not included in the categories of facilities that have a proposed RTC reduction, see Tables 7 and 8 in PAR 2002. See also Response 1-1.

1-4 This comment requests that only significant contributors of NOx (e.g., top emitters) with the potential to achieve major reductions in NOx emissions should be subject to the NOx RTC shave.

This comment is a summary of the concerns expressed in Comments 1-1 through 1-3. See Responses 1-1 through 1-3.

Comment Letter #2

Air Products and Chemicals, Inc.
23300 S. Alameda Street
Carson, CA 90810
Telephone (310) 847-7300

30 January 2015

Attn: Barbara Radlein
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Air Products and Chemicals, Inc. – Comments on Proposed NOx RECLAIM Shave Approach

Dear Ms. Radlein:

On behalf of Air Products and Chemicals, Inc. (Air Products) we appreciate the opportunity to comment on the approach that should be utilized for conducting a NOx RECLAIM shave. Air Products operates two (2) "new" RECLAIM facilities: Carson Hydrogen Plant (Facility ID 3417) and Wilmington Hydrogen Plant (Facility ID 101656). Both facilities' primary RECLAIM equipment are major source reforming furnaces (>750 MMBTU/hr) and both utilize selective catalytic reduction (SCR) for NOx control. 2-1

Our primary concern is regarding our Carson Hydrogen Plant where we had purchased two (2) infinite block streams of RECLAIM Trading Credits (RTCs) well before the 2005 NOx RECLAIM shave. These infinite block streams were acquired to cover facility NOx emissions (reforming furnace is only RECLAIM source at Carson) based on an initial, permitted BACT NOx limit of 5 ppmv @3% O2 (3-hr average). Our understanding, based on any recent/similar permitting projects, is that this level of NOx is still considered BACT at this time for hydrogen reforming furnaces. 2-2

Upon review of District staff draft report "Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM)" (December 2004), it does not appear either of Air Products reforming furnaces, as non-refinery heaters >750 MMBTU/hr and not subject to Rule 1146, were evaluated for BARCT. Nonetheless, Carson Hydrogen Plant, like all of the RECLAIM facilities, was subjected to the ~20% across-the-board shave; however, the facility has since been able to continue to cover NOx emissions using the reduced infinite block streams through increased SCR ammonia injection and more frequent SCR catalyst change-outs. 2-3

Fast forward to the currently proposed across-the-board shave of ~50% and it appears that still neither of Air Products reforming furnaces was evaluated for BARCT. Based on the cumulative effect (~60%) of the 2005 reduction (~20%) and currently proposed reduction (~50%), the District is essentially forcing the Carson Hydrogen Plant, as a source where no BARCT limit has been identified and no more stringent BACT limit exists, to either operate at ≤2 ppmv NOx levels (which would likely not be possible without significant and expensive SCR equipment modifications due to current system limitations and/or taking into account NH3 slip limit) or purchase RTCs on the market whose cost, as an infinite block stream, could easily exceed $1 million. 2-4

-2-

We feel that the most fair and equitable manner is to apply the shave such that it is only impacting facilities where actual reductions have been identified through new 2014 BARCT limits. By applying the shave across the board there can be, as described above for example, significant financial impacts to sites and sources that were not evaluated and may already be operating at levels considered as current BACT. While Air Products appreciates the complexity of doing something other than an across the board shave in a free trade market such as RECLAIM; we feel that the District has a responsibility to look closer at possible methods that could exempt sources from a shave where no reductions have been evaluated and identified; such as: 2-5

- Segregating all RTCs into two different types that can be used to cover sources/facility emissions; one type where a 2014 BARCT limit has been identified and one type where a 2014 BARCT limit has not been identified.
- An option to "lock-in" current infinite block stream(s) a facility holds (as of some previous date) for life or until any future RECLAIM shave may occur with an applicable BARCT limit for that facility.

Please feel free to contact me at (310) 847-7300 or by email at reebeljc@airproducts.com if you have any questions or would like to discuss further. Thank you.

Sincerely,

Jim Reebel
Principal Environmental Engineer

cc: Chris McWilliams, So Cal Plant Manager
Brent Walker, Area Business Manager
Brian Keck, Environmental Manager

File: CA/Carson/AQMD Correspondence

RESPONSES TO COMMENT LETTER #2
(Air Products and Chemicals, Inc. - January 30, 2015)

2-1 This comment introduces the commentator's facilities and identifies the primary equipment sources of NOx RECLAIM emissions. No response is necessary.

2-2 This comment inquires as to whether BACT for a hydrogen reforming furnace is going to remain at five ppmv NOx at 3% O_2 because the commentator's facility had previously acquired two infinite block streams of NOx RTCs prior to the 2005 NOx RECLAIM shave to cover emissions from this type of equipment.

SCAQMD staff did not propose a new BARCT for reforming furnaces. SCAQMD staff conducted a BARCT analysis for several source categories among the top emitting facilities for compliance year 2011. The analysis demonstrated that SCR is the preeminent technology for achieving NOx emission levels at two ppm at 3% O_2 for combustion sources. As part of the BARCT analysis, some equipment, such as boilers and engines, were also evaluated for those facilities outside the range of the top emitting facilities. While the process is referred to as hydrogen reforming, the equipment is considered a heater/furnace with a heat rating greater than 50 MMBTU/hr. This is not different from a large boiler/heater or a refinery boiler and heater that would be subject to 2ppm BARCT. While there were many refinery boilers and heaters that were analyzed do have cost-effective BARCT, the analysis of reforming furnaces was based on the vast majority of the boilers and heaters in the non-refinery sector and determined to be not cost effective. Thus, SCAQMD staff did not propose a new BARCT for reforming furnaces.

2-3 This comment states that the staff report for the 2005 NOx RECLAIM amendments did not conduct a BARCT evaluation of reforming furnaces or non-refinery heaters rated greater than 750 MMBTU/hr and not subject to Rule 1146. This comment also states that in response to the 20 percent shave applicable to all NOx RECLAIM facilities as part of the 2005 NOx RECLAIM amendments, the commentator's facility, in response to that shave, increased ammonia injection into the SCR and implemented more frequent SCR catalyst change outs in addition to applying the purchased infinite block streams to cover the emissions.

For any gaseous fueled heater that is rated above five MMBTU/hr and is operated at a facility that is not subject to the RECLAIM program, the requirements in Rule 1146 would apply. Thus, contrary to the comment, RECLAIM heaters were subject to BARCT as part of the 2005 NOx RECLAIM amendments. Since the shave for that rule amendment was an across the board approach, all facilities in NOx RECLAIM had their RTCs reduced.

2-4 This comment claims that the current proposal of a 50 percent shave also does not include a BARCT evaluation of reforming furnaces. This comment states that the cumulative effect of the 2005 NOx shave, when combined with the current proposed 50 percent shave, will have an overall effect of reducing RTCs at the commentator's facility by 60 percent. The comment also claims that the commentator's facility will either need to operate at less than or equal to two ppmv NOx levels by making expensive modifications to existing SCR equipment or by purchasing over $1 million of RTCs.

As explained in Response 2-2, SCAQMD staff did not propose a new BARCT for reforming furnaces. The commentator is correct that no BARCT analysis was conducted for reforming furnaces. The staff proposal does not shave offsets at the commentator's facility; the emission reduction calculations and associated costs are not germane to the current staff proposal. The current staff proposal, in addition to relying on a BARCT analysis, also proposes to shave excess RTCs in the market since unused RTCS can be used to emit at levels exceeding BARCT.

2-5 This comment suggests that the shave be applied only to facilities where actual reductions have been identified via new 2014 BARCT limits to avoid significant financial impacts to sites and sources that were not evaluated and that may already be operating at current BACT levels. This comment suggests exempting sources/facilities from the RTC shave if no 2014 BARCT limit has been identified. This comment also suggests that the proposed amendments include a provision that would segregate RTCs into two categories – one for equipment with BARCT and one without or allow an option to "lock in" current infinite block streams that a facility holds, until such time that a future BARCT limit would apply specifically to that facility's equipment.

Certain facilities are included in the shave even though there may be no new 2014 BARCT because they hold large amounts of RTCs that are not needed. See also Response 2-4 regarding the proposed RTC shave. CEQA alternatives which would have an across the board reduction have been included due to comments from some industry representatives. However, the staff proposal has the reductions described in previous responses.

Regarding the suggestion to have different classifications for RTCs, doing so would introduce significant complexity to the program and create uncertainties in the market, which staff does not support.

Comment Letter #3

CALPORTLAND

January 30, 2015

South Coast Air Quality Management District
Ms. Barbara Radlein (c/o CEQA)
21865 Copley Drive
Diamond Bar, CA 91765

Sent via E-mail (bradlein@aqmd.gov)

RE: California Portland Cement Company
695 S. Rancho Ave., Colton
Facility ID#800181

Dear Ms. Radlein:

CalPortland is submitting the attached comments for the proposed amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM). If you have any questions, please contact Jay Grady at (626) 852-6262 or jgrady@calportland.com.

Sincerely,

Jay M. Grady
Director, Environmental Affairs

Cc: Kevin Orellana (korellana@aqmd.gov)

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Comments on Initial Study for: Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) December 2014, and the Following Support Documents: ETS Inc.'s NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-refinery Sector dated November 26, 2014.

January 30, 2015

COMMENTS PREPARED FOR: CalPortland Company for Submittal to SCAQMD

COMMENTS PREPARED BY: Schreiber, Yonley & Associates

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1.0 Summary of Key Comments

After a thorough review of the Draft Program Environmental Assessment (PEA) for the proposed amendments to SCAQMD Regulation XX, Regional Clean Air Incentives Market (RECLAIM) dated December 2014, and related support documents by ETS, Inc., CalPortland and its consultants Schreiber, Yonley & Associates have identified significant problems with the documents and the process utilized to develop the control options in those documents and the associated emissions reductions contained in these documents. The following comments address these deficiencies:

1.1 The Administrative Process was Flawed

During the public meetings and throughout the rulemaking process, CalPortland Company (CalPortland) and their technical consultants were given no opportunities to provide critical process details to either the SCAQMD, its contractors, or the vendors providing proposed control technology options, cost quotations for the proposed controls, or proposed control efficiencies for those control options. Furthermore, although CalPortland began requesting the detailed cost spreadsheets from which the Cost Effectiveness Table for cement kilns was derived as early as July 2014, none of this information was made available to CalPortland until late in the day on January 23, 2015. That information contained only very general spreadsheets (which leave many questions and concerns unanswered). Further, Confidential Appendices A of the ETS, Inc. Final Report, dated November 26, 2014, was not provided to CalPortland until January 20, 2015, ten days before the comment period ended. CalPortland was told that vendor communications, design details, cost details, warranty information and/or clarification information was confidential. We are at a loss as to how vendor information regarding control strategies would be confidential from the affected facility but this is what they were told by District staff.

The failure to provide critical documents related to the cost estimates and control technology design information during the regulatory development process has essentially denied CalPortland a voice in this regulatory process. Further, CalPortland was treated differently in this regard than other regulated industries. Not only does the withholding of critical information during this process deny CalPortland an opportunity to be heard during the process, but also prevents CalPortland from having the ability to thoroughly evaluate the PAE and the ETS, Inc. review of the cost analysis, it further denies CalPortland the ability to determine if the technical basis/design basis for the controls, the proposed control efficiencies and therefore the basis for the proposed emissions reductions in the proposed amendments to the regulation. Essentially, the flawed process prevents CalPortland from making fully informed comments on the proposed amendments.

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1.2 Inconsistencies Exist Between the PEA and Cost Analysis Control Options

The three control technology options listed in the PEA are not consistent with the control technologies listed and evaluated in the Cost Analysis and the ETS evaluation of the cost analysis.

1.3 There are Significant Technical Concerns with the Control Options in the Cost Analysis

The characteristics of the emissions from cement kilns vary from kiln to kiln due to differences in the type of cement kiln, the fuels utilized, and the chemical characteristics of the raw materials. The vast majority of the raw materials utilized by cement kilns are mined onsite and not only vary from site to site, but also may vary within the onsite quarries. These site specific conditions are critical to the design of emissions control equipment. Critical site-specific characteristics include process information that is not included in reports/documents submitted to regulatory agencies. Critical design parameters include not only the average values, but also the minimums and maximums. The failure to allow CalPortland access to the vendor documents jeopardized the validity of the design basis. Further, based upon knowledge of the differences between the CalPortland kilns and the kiln gas characteristics from the limited number of other kilns which have utilized SCR systems, the CalPortland kilns are significantly different. The SCR systems on other kilns operate at significantly higher gas temperatures. Further, when a low temperature catalyst was pilot tested on a cement kiln at similar gas temperature and which also experiences SO_2 spikes similar to CalPortland, the catalyst was poisoned within less than three months. The Ultracat option to our knowledge has not had any long term application on a cement kiln.

Finally, the SO_2 control options proposed to control the SO_2 spikes will have little to no impact on typical SO_2 emissions levels at CalPortland. This is because the average SO_2 emissions from CalPortland are below concentrations where these controls are effective. While there may be control during the SO_2 spikes, either SO_2 control option proposed by the vendors will have a lag time to react to the increased concentrations during emissions spikes, and therefore the catalyst will not be sufficiently protected from SO_2 poisoning.

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1.4 Cost Effectiveness Analysis

The estimated costs provided in the cost analysis are impossible to fully evaluate without having the design basis and supporting detailed cost estimation spreadsheets. Nevertheless, the capital and annual costs appear to be too low and it is unclear if they fully address site specific construction conditions, costs for treatment of the wastes generated by the WGS, a realistic frequency for catalyst replacement/reactivation/disposal and other site specific costs. CalPortland acknowledges that even with corrected cost estimates, the cost effectiveness is unlikely to exceed SCAQMD criteria of $50,000 per ton pollutant removed. However, the cost analysis fails to address one way in which CalPortland differs from the majority of the other industry categories impacted by the Proposed Amended Regulation XX. CalPortland will not be able to pass these cost on to customers through increases in the price for cement. The cement industry is highly competitive. The proposed controls would result in an increase of $10 or more per ton of cement. This will not only price CalPortland out of the local market with local competitors that are not subject to SCAQMD RECLAIM program, but for that price difference cement can be imported from Asia at a lower price.

1.5 CalPortland's Emissions Rate

To our knowledge CalPortland's current NO_x emissions limit of 2.73 lb/T clinker (T_c) already represents the lowest emission limitation for long dry cement kilns. Typical long dry kiln emission rates are in the range of 8-12 lb NO_x/T_c, which is represents the uncontrolled emissions rate from the Colton kilns, and the existing limitation is already a 65-77% reduction in NO_x emissions for a typical uncontrolled long dry kiln.

BARCT emissions limits should be essentially the same as BACT. Retrofit controls should not be expected to be more stringent than controls that are designed and integral to a new source. The emissions limit under the New Source Performance Standards for a new cement kiln is 1.5 lb/Tc which was adopted recently by EPA after a very thorough technology review (which included a review of SCR). CalPortland has proposed to add SNCR to the NO_x controls already in place at the plant and believes that an additional reduction in NO_x emissions of 30-40% can be achieved. The result would be an emissions rate in the range of 1.64 -1.91 lb NO_x/T_c. At that emissions rate, it is believed that the emissions from the Colton kilns would be lower than the emissions from the Joppa, IL long dry kiln which utilizes SCR.

2.0 Introduction

In a cement kiln, raw materials containing the necessary ratios of calcium, alumina, silica and iron are blended, ground to the required fineness in the raw mill and pyroprocessed at very high temperatures (material temperatures of 2700F) at which the materials liquefy and react to form a complex mixture of compounds referred to as clinker. **Note that clinker is not "..lumps of limestone and clay)" as stated in paragraph 5, page 1-16, of the PEA.** The chemistry of the raw materials and fuels and the operation of the kiln are critical to making clinker that will meet cement quality specifications. NO_x emissions are the result of the combustion of the nitrogen found in the fuels and the oxidation of the nitrogen in the combustion air due to the high temperatures in the combustion zone. **Note that the statement found in the PEA, Page 1-17, paragraph 3, ..., 2) oxidation of sulfides (e.g. pyrites) in the raw materials entering the cement kiln." is incorrect. The oxidation of sulfides form SO_2 not NO_x.**

There are several types of cement kilns in operation in the United States today, these are: long wet kilns, long dry kilns (CalPortland's Colton, CA kilns are this type), preheater kilns, and preheater/precalciner kilns. All new kilns built today are preheater/precalciner kilns (PH/PC). PH/PC kilns are more energy efficient, minimize waste (significantly reduce or eliminate the generation of cement kiln dust (CKD) requiring landfilling) and are designed to produce lower pollutant emissions, including GHG, than the earlier kiln designs. Pollutant emissions from cement kilns are directly related to the chemistry of the raw materials utilized. Because the vast majority of these raw materials are mined onsite, typically 85 percent or greater, the emissions from each kiln are site-specific. Therefore, the design of emissions controls must also be site-specific as will be the potential reduction in emissions from those controls.

3.0 Comments on Proposed Control Options

The draft PEA, page 1-17, paragraph 4 lists the 3 potential available control technologies for cement kilns as:

1. SCR with or without a WGS;
2. Ultracat; or
3. SNCR

All of the cost effectiveness documents list and evaluate the following three control options:

1. Vendor 1: SCR system installed between waste heat boiler and baghouse
2. Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse
3. Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse.

Note that the cost effectiveness documents do not include analysis of SNCR nor did the PEA discuss the heat exchanger option with SCR. The remaining comments in this section will focus on the three alternatives evaluated in the cost effectiveness documents first focusing on technical concerns with the proposed technologies and then addressing the cost estimates themselves.

The existing gas flow is as follows: the gas exits the kiln and passes through a series of 4 cyclones and a multiclone then is ducted to a waste heat boiler (WHB). Then the gas is ducted back to the inlet to the baghouse and then exits through the kiln stack. The temperature of the gas entering the waste heat boiler is in the 900 - 1200°F range and the temperature exiting the waste heat boiler is around 350°F. Figure 1 below illustrates the existing gas flow.

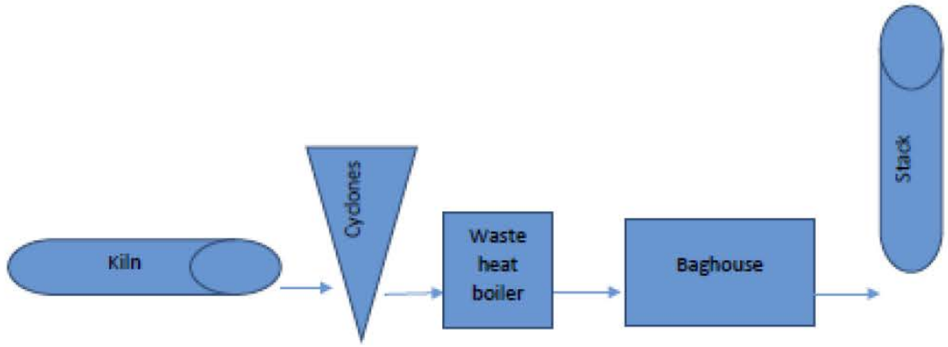

Figure 1: Existing Kiln Gas Flow Diagram

3.1 Vendor 1

Vendor 1 proposed to install a SCR between the waste heat boiler and the baghouse. In reality, the SCR would not physically be located between the waste heat boiler and the baghouse as there is physically no room to install an SCR there on either kiln. Figure 2 is a photograph of the kiln baghouses and stacks and illustrates the physical constraints and physical size of the equipment.

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Figure 2: Photo of Kilns and Baghouses

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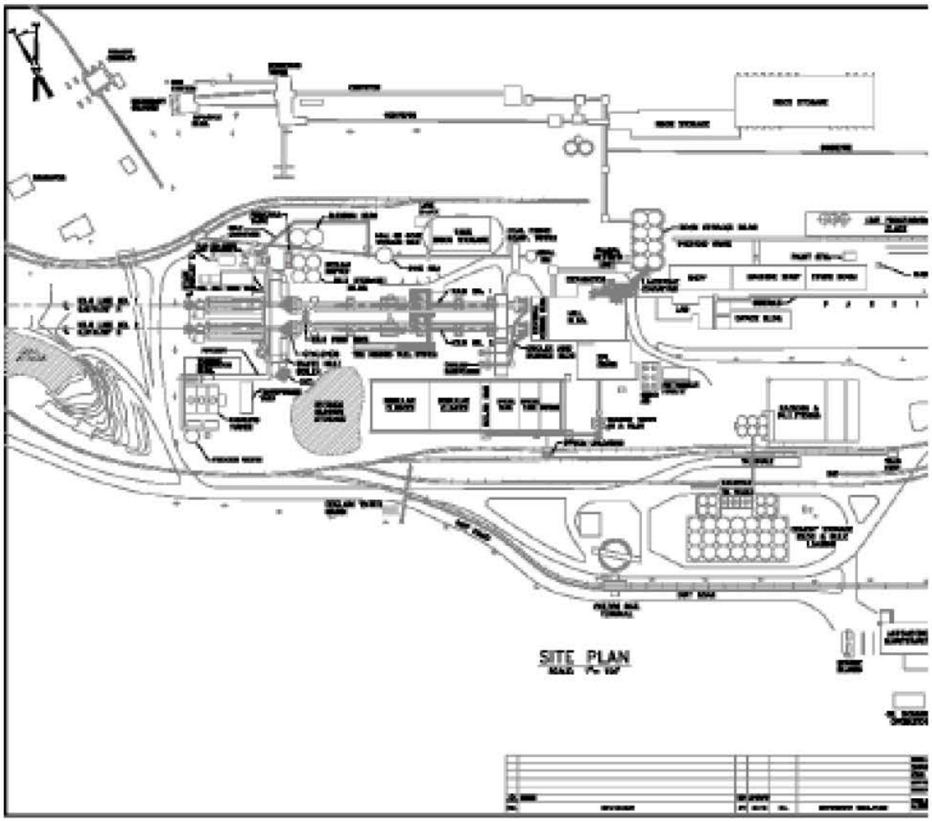

Figure 3: Site Plan

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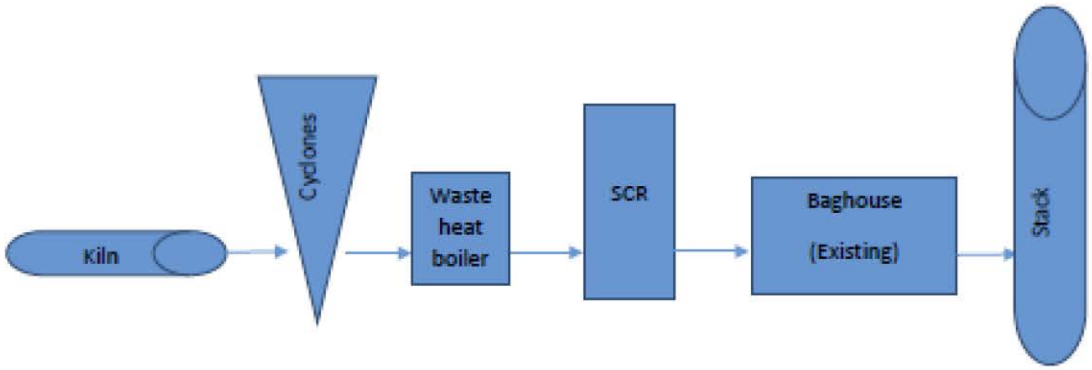

Figure 4: Gas Flow Diagram for Vendor 1 Option

Figure 3 above shows the existing equipment at the site. As is obvious from the site plan and the photo in Figure 2, the SCRs cannot physically be located between the waste heat boilers and the baghouses. The existing coal pile and handling systems are north of the baghouses and cannot be moved due to fugitive emissions constraints as well as proximity to coal unloading and handling equipment. Therefore, the SCRs would need to be located in the area north of the kilns, Co-generation facility or rail lines, requiring the ductwork to go above existing equipment 150-200 feet to the SCR and then back 150 -200 feet to the baghouse inlets. This ductwork would need to be insulated and the SCR and ductwork construction would need to comply with local seismic construction codes. As noted in the initial summary. CalPortland has been denied access to the vendor design basis based on confidentiality of the vendor information and the cost spreadsheets provided on January 23, 2015 do not contain sufficient detail to make a determination. Therefore, it is unknown whether the increased construction costs, potentially 20% or more, to comply with local seismic codes were included in their cost estimates.

ETS noted in their report that there has been conflicting information provided regarding the temperature of the gas returning from the waste heat boilers. Initially 300-350°F, then an indication that it might be 450-500° F and then in October 2014, 350°F. ETS indicated that Vendor 1 indicated that an additional layer of catalyst would be needed at a lower temperature of 450°F. Obviously, since their costs were provided to the SCAQMD prior to that time, and have not been revised by ETS other than to include a 15% contingency, the cost for the SCR both capital and annual would need to be increased to include the costs for installing and operating with an additional catalyst.

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It is also unclear whether the current ID fan would be adequate to meet the additional pressure loss across the SCR and the lengthy ductwork to and from the SCR, or whether the cost for replacement ID fan was included in the vendor cost estimate. CalPortland believes a new fan would be necessary. Based upon knowledge of costs for other cement SCR systems, even with the ETC contingency adjustment, Vendor 1's costs appear to be significantly low.

However, the greatest concern with the Vendor 1 proposal is the impact of the gas temperature on the efficiency of the catalyst to control NO_x, and more importantly, the impact of the SO_2 emissions on the catalyst when the SO_2 spikes. The catalyst converts SO_2 to SO_3. . Below 450°F, any ammonia injected for the NO_x reaction will react to form ammonium salts, $(NH_4)_2SO_4$ and NH_4HSO_4 , which poison and plug the catalyst (see chart in Appendix A). This is particularly true for the more reactive catalyst formulations required for lower gas temperature applications. A pilot test with a low temperature catalyst on a cement plant with similar gas temperature and which although SO_2 was typically low, experienced occasional spikes in SO_2 was unsuccessful due to sulfur poisoning. Even with duct burners, as suggested by ETS to address temperature loss between the waste heat boiler and SCR, temperatures would not be expected to be above the 450°F necessary to prevent the formation of ammonium salts and catalyst poisoning. Therefore, regardless of the addition of duct burners, which would generate additional combustion emissions including NO_x, the SCR proposed by Vendor 1 is unlikely to be technically feasible.

3.2 Vendor 2

Vendor 2 proposed to place a dry scrubbing system after the waste heat boiler to address concerns with SO_2 emissions then follow that with a ceramic filter system in place of the existing baghouse. Figure 5 below is a diagram of the gas flow for this scenario.

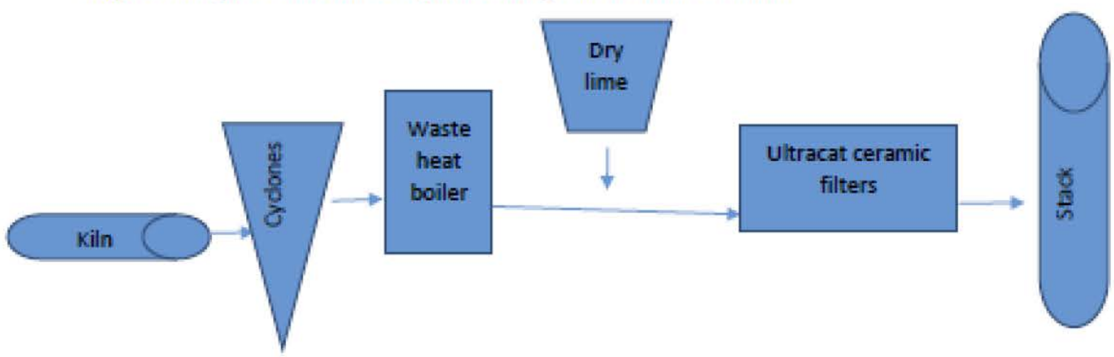

Figure 5: Vendor 2 Proposed Control Gas Flow Diagram

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It is believed that Vendor 2 included the dry scrubbing system to address concern with catalyst poisoning due to the SO_2 concentrations and the gas temperatures. However, there are two technical concerns with this approach. First, the temperature of the gas stream exiting the waste heat boiler is at or near the temperature for the lowest SO_2 reduction efficiency, perhaps 30% control. Second, because of the high dust loading in the gas stream as well as other factors, a CEMS system to monitor the SO_2 concentration prior to the lime injection location, upstream of the ceramic catalyst (Ultracat) system cannot be used because the sample probe cannot endure the conditions in the gas stream (high dust concentration). Therefore, the stack CEMS would be the first indicator of the SO_2 spike and by this point the catalyst would already have some exposure to the increased SO_2 levels. By the time a spike is noted and the control system increases the lime injection rate, some level of catalyst damage would likely have already occurred.

Ultracat's vendor literature, available from the internet, and conversations with the vendor for a different, but similar application, indicate that NO_x control becomes effective at 350°F but does not achieve high (90%) efficiency until gas temperatures above 400°F.

Without access to the vendor's design basis and more details than the spreadsheets provided on January 23, 2015 include, it is not possible to comment on the proposed cost effectiveness calculations other than to express concerns on whether the costs account for construction compliant with seismic codes and the need for a contingency. Given that, to our knowledge, the Ultracat system has not been installed for full scale, long term application at a cement kiln, a contingency of greater than 15% would be warranted. Further, annual costs are somewhat speculative due to unknown life of the ceramic catalyst filter system in a cement application.

The Ultracat ceramic filter system is untried on a full-scale long-term application for a cement kiln. Given the differences in cement plant applications compared to other applications, CalPortland does not believe that it meets the criteria for a demonstrated control technology for this application especially for a definition of a best available "retrofit" technology. Further, although the vendor literature indicates that their product will control particulate emissions to levels that comply with the 40 CFR Part 63, Subpart LLL (the NESHAPS for portland cement manufacturing), CalPortland is unaware of any long-term application of the technology on a cement kiln and cannot verify that it will comply with the new emissions limitations for PM in routine cement application.

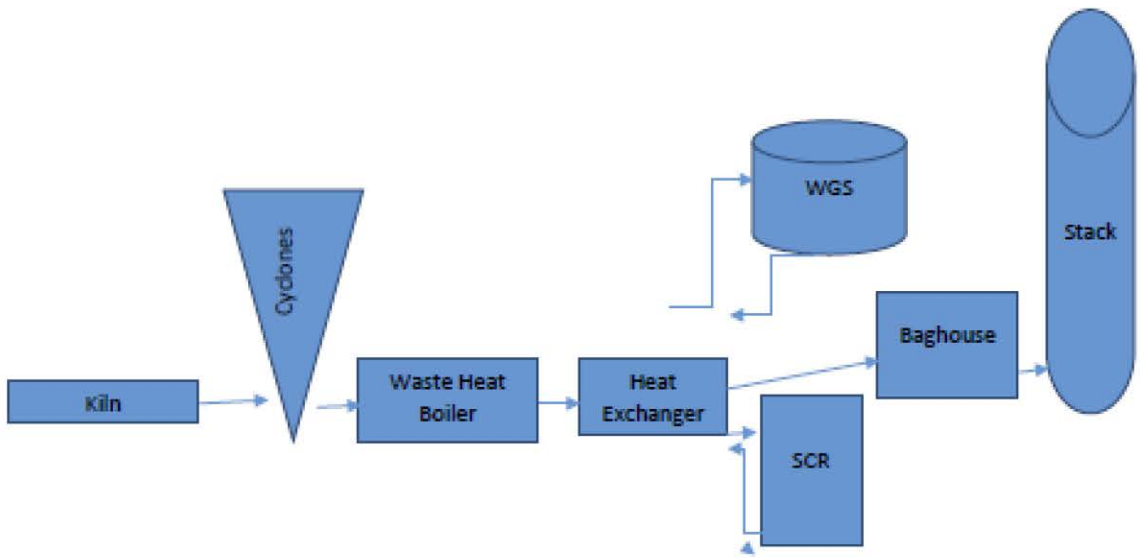

Figure 6: Vendor 3 Proposed Control Gas Flow System

3.3 Vendor 3

Vendor 3 proposes to utilize a wet gas scrubber to address the SO_2 in the gas exiting the waste heat boilers, a heat exchanger to increase the gas temperature for the SCR and then replace the existing baghouse. Figure 6 below illustrates the kiln gas flow through this control system.

The wet gas scrubber is proposed to reduce SO_2 emissions prior to the SCR. However, the typical concentration of SO_2 in the gas stream is between zero and 10 ppm and typically in the 2 ppm range. Discussions with a wet scrubber vendor confirmed that there is a lower limit/concentration that they will guarantee. For a wet lime scrubber, the type currently utilized at the few cement kilns with wet scrubbers, the lower limit for the warranty for the concentration of SO_2 in the scrubber exit gas is 10-12 ppm, a caustic scrubber, as proposed by Vendor 3, might be slightly lower, but still would have no impact on a 2 ppm stream. Therefore, under typical kiln operations the WGS will provide no impact/control of SO_2 because the emissions are below the effectiveness of the technology. Essentially, when a control technology utilizes a reagent which must react with the pollutant in the gas stream, the pollutant molecule and the reagent molecule must come into contact with each other for the reaction to occur. The lower the concentration of the pollutant, the lower the potential for the reaction to occur. Therefore, during typical operations the WGS would be utilizing significant energy, for little to

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no reduction in SO_2. The same issue exists for a CEMS probe for this control options as existed for the Vendor 2 option in the probe in the WGS inlet duct will not survive. Therefore an alternate mechanism for determining the necessary molar concentration for the regent in the scrubber liquid and the reagent addition rate is needed. The vendor contacted indicated that the control system measures the acidity of the scrubber liquid and when it reaches a set point, additional reagent is added. The control loop takes some time to fully address a spike situation. Like the dry reagent/lime addition proposed by Vendor 2, some damage to the SCR catalyst will occur before the system can react to the spike. It is not clear why the vendor specified a caustic scrubber when lime scrubbers are typically utilized for a cement kiln application. Further, the cost spreadsheets do not appear to include the capital costs for a scrubber wastewater treatment system or the costs for the disposal/discharge of the wastewater after treatment.

It is unclear at what temperature the SCR in this control option would operate. There is no discussion of an additional heat source to raise the gas temperature above the temperature at which it exits the waste heat boiler. Therefore it is assumed that the heat exchanger is proposed to maintain that temperature rather than to increase the temperature to the temperature range of the currently operating SCR systems on cement kilns.

Table 1 below lists the gas inlet temperatures for the cement kiln SCR applications. This information was taken either from the vendor website for a particular plant, or from papers presented by either the vendor or owner of the cement plant.

Location	Operating Temperature (°F)
Solnhofen, Germany	572-608
Monselice, Italy	608-626
Sarche, Italy	666-750
Mergelstetten, Germany	716-750
Rohrdorf, Germany	550-660
Mannersdorf, Austria	570-660
Joppa, Illinois	572
Rezzato, Italy	590-626

Table 1: Operating Temperatures of Existing Cement Kiln SCRs

It is important to note that, whether the SCR is low-dust, semi-dust or high-dust application, the gas inlet temperature to the SCR is between 550°F and 750°F. Only one of these applications reheats the gas stream, and in that instance there are no waste heat boilers utilizing the available waste heat from the process to minimize/eliminate the combustion of additional fuels which would generate combustion emissions.

ETS, in their review indicate that they corresponded with USEPA regarding the SCR on the Joppa, IL cement kiln. The plant has not yet completed their written report on the SCR, but USEPA reported that 70-80% NOx reductions were being achieved. Although the Joppa kiln is also a long dry kiln, it is not equipped with waste heat boilers. In addition, the hot kiln gases are routed through a hot ESP which significantly reduces the dust-loading prior to the gas entering the SCR. Therefore, the Joppa SCR utilizes a typical high temperature catalyst, operating at 572°F versus the 350°F at CalPortland's Colton kilns, the catalyst is not as reactive to SO_2 as the catalyst formulation necessary for CalPortland. The Joppa SCR operates at a temperature well

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above the temperature below which ammonium salts are a problem (450°F). Further, the dust loading to the catalyst is significantly reduced improving catalyst reliability.

3.4 Summary of Control Technology Evaluation

Due to the temperature of the gas stream exiting the waste heat boilers, there are concerns with the technical feasibility of all three control options evaluated for cost effectiveness. As previously discussed these concerns are directly related to the impact of SO_2 spikes combined with gas temperatures in the range where ammonium salts form (below 450°F). These salts poison the catalyst. The only SCR application which utilized a lower temperature catalyst in a cement plant application that we are aware of, was a pilot test which was a failure due to catalyst poisoning. Of the SCRs listed in Table 1, Sarche and Rohrdorf are low dust applications and therefore have not, and would not be expected to experience problems with dust loading on the catalyst. However all of the others with the exception of Joppa and Rezzato, for which information is not yet publically available, the SCRs experienced significant issues with the catalysts in the first years of operation and replaced and/or regenerated the catalysts multiple times in the first years of operation until catalyst pitch sizing was addressed and dust removal mechanisms were modified and became operational. Each cement kiln has site-specific gas chemistry and characteristics. CalPortland's Colton kilns are not currently operating and thus key design parameters cannot be measured or analyzed.

The current allowable NO_x emissions rate for CalPortland's Colton kilns is 2.73 lb NO_x/T_c. This represents a reduction of approximately 65-77% from uncontrolled emissions rates (uncontrolled NO_x emissions ranged from 8-12 lb/T_c). CalPortland believes that the addition of SNCR to their current controls will reduce NO_x emissions another 30-40% for a final emissions rate between 1.64-1.91 lb NO_x/T_c, which would constitute roughly a 75-85% reduction in emissions below the uncontrolled emissions rate and result in a total control efficiency in the same range as what the Joppa plant is achieving with a high temp, semi-clean, SCR system. At that emissions rate CalPortland believes that their emissions might actually be lower than the emissions rate achieved by Joppa. The emissions level at Joppa will not be available until the Joppa Demonstration Report is submitted. Further, SNCR is not adversely impacted by SO_2 spikes, can be installed and operational on the Colton kilns at or shortly after startup of the kilns. In contrast, the installation of any of the three vendor control options will take at least a year for pilot testing and multiple years to install.

4.0 Flaws in the Administrative Process

4.1 CalPortland Denied Access to Vendor Information

Throughout the rulemaking process, CalPortland repeatedly requested access to the vendors' design basis and the details of the vendors' cost information and requested to meet with the vendors to ensure that they fully understood the kilns system and kiln gas characteristics that impact design, CalPortland has not had any opportunity to discuss vendor information with the District or the vendors and was not provided the detailed design basis or detailed cost spreadsheets necessary to determine the validity of the design or costs. CalPortland was told that the information was confidential. We are at a loss as to how vendor information regarding control strategies would be confidential from the affected facility, but this is what CalPortland was told by SCAQMD staff. The very basic cost spreadsheets provided on January 23, 2015, do not address all of CalPortland's questions or concerns.

Questions not addressed or answered by the vendor cost spreadsheets that were provided are as follows:

1. Were the vendors notified of the updated temperature information for the gas stream after the October 2014 site visit by ETS? Vendor costs were not changed from the summary cost spreadsheet provided in July 2014 to the spreadsheets and costs in the November ETS and December PEA. ETS indicates that Vendor 1 modified their design to include more catalyst after they were notified of a temperature of 450°F. Would additional changes need to be made for the actual temperature of 350°F? Further, given that the actual temperature is well below the temperature for ABS formation, would any of the vendors warranty the designs they quoted at this lower temperature given the additional knowledge that emissions of SO_2 spike up to 1500 ppm?

2. The annual costs for catalyst replacement vary significantly between Vendor 1 and Vendor3 for the same control of the same gas stream. There is no explanation for the discrepancy. Further, although the two vendors are consistent in indicating 3-year catalyst life, this life is questionable given the history of SCR at other kilns. CalPortland has knowledge of a recent SCR catalyst warranty of two years. There is no indication in the spreadsheets provided that pilot testing of a gas slip-stream is planned or included in the costs. Even with pilot testing, previously constructed SCR systems on cement plants have routinely had to change out catalysts multiple times in the first years of operation.

3. There is no mention in the, PEA, the ETS documents or the vendor spreadsheets regarding the need for the controls to operate for the gas stream at both potential operating conditions. While the waste heat boilers operate when the kilns operate under normal conditions, they may not always do so. For example, a malfunction or need for maintenance on the WHB would not result in shutting down the kiln. First, it takes significant amounts of time to safely and properly shut down a cement kiln. Further, some level of thermal shock to the kiln refractory occurs even when kilns are shut down properly. Therefore, the kilns would continue to operate even if the associated WHB needed to be taken offline. The emissions control systems would need to be able to operate at both gas stream conditions, higher temperature (in excess of 900°F) when the WHB is offline and the low 350°F temperature when the WHB are in use.

4. There is no mention or apparent cost included by any of the vendors to replace the existing kiln ID fans. The additional pressure drop resulting from any of the three control scenarios would necessitate the replacement of the kiln ID fans.

5. The reports and the vendor spreadsheets make no mention of the additional construction costs associated with construction to the new stringent seismic codes. It does not appear that the these additional costs, which could be as much as 20% or more, have been included in the vendor costs.

6. As previously noted, it does not appear that Vendors 1 and 3 have included the costs and time required to conduct a slip stream pilot test prior to the design and construction of the full scale control systems. Pilot testing is essential to allow the design to address site-specific conditions.

7. Vendors 2 and 3 propose removal of the existing baghouses and footnote their spreadsheets that they haven't adjusted their costs for any salvage value of the existing baghouses. However, they do not specify whether their costs include the demolition costs for the existing baghouses.

8. Without being provided all of the correspondence related to the gas stream specifications requested by and provided to the vendors, it is not clear whether the vendors are aware of the extremely low typical concentrations of SO_2, 2ppm range, and the magnitude of the spikes which can reach 1500 ppm.

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9. Vendor 2 proposes a product that to our knowledge has not been in long-term cement plant application. Does the vendor warranty that the system can comply with the particulate limits in 40 CFR Part 60, Subpart LLL? Can this technology even be considered to be demonstrated technology in this application?

10. Vendor 3 proposes a caustic scrubber for SO_2 control. The costs do not appear to include the capital costs for a waste water treatment system or the costs to operate that system or dispose/discharge treatment residues/wastewater. The few existing wet scrubber systems on cement kilns utilize lime rather than caustic for compatibility with the process. No information was included to justify the use of caustic rather than lime in the scrubbers for CalPortland.

Confidential Appendix A of the ETS Final Report, dated November 25, 2014 was not provided to CalPortland until January 20, 2015, only ten days before the close of the comment period. Although ETS notes in Section B, Paragraph number 3 on Page 3 of the Confidential Appendix A that: "Project documentations shows much contact and discussions with some willing vendors on the subjects of potential problems and steps for resolving them. Problems and concerns were presented by the facility were factored into the costing, e.g. adding caustic scrubbers, a heat exchanger system and soot blowers." There was no direct communication between CalPortland and the vendors and CalPortland was never provided the details of the design basis utilized by the vendors. Without an opportunity to speak directly to the vendors to provide site specific information critical to design that was not requested by the SCAQMD nor contained in documents or reports requested or required to be submitted to the District, or at the very least an opportunity to review and comment on the information provided to the vendors and by the vendors CalPortland was denied the opportunity to constructively participate in the control selection and evaluation process. Without access to the design basis details of what equipment is included in the cost estimates, CalPortland cannot fully evaluate the technical feasibility of the proposed control options, the reported costs for those controls or whether those controls can actually achieve the emissions limit contained in the proposed amended Regulation XX.

4.2 Vendor Costs were not revised even though SCAQMD and ETS were made aware Lower Gas Temperatures at least by Mid-October 2014.

CalPortland acknowledges that there were discrepancies in gas stream temperatures discussed with SCAQMD at different points in time. However, the gas temperature for the gas exiting the waste heat boiler/entering the baghouse provided to SCAQMD in February 2014 was 300-350°F and the temperature provided in October 2014 was 350 °F. There was adequate time for the vendors to revise costs estimates to address this lower temperature. In review of ETS's discussion on Page 4 of the Confidential Appendix A, it appears that either the SCAQMD told the vendors initially to utilize the temperature of the gas exiting the kiln, prior to the waste heat

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boilers, or provided some other temperature. Section C, Paragraph No. 1 on Page 4 as the discussion notes that ""...All vendors offered technical advice as well as costing revisions (if warranted) to account for the lower temperature range of (450-500°F after the WHB)." Paragraph No. 4 on the same page confuses the temperatures even more. Further, after the October 2014 site visit where ETS was informed that the gas temperatures were 350°F, no revisions were made to the costs to address this lower temperature although ETS speculates that duct burners can be utilized. It is unclear whether the vendors were ever made aware of the 350°F gas temperature. This is critical to the validity of the design, costs, technical feasibility of the proposed control options, and the ability of those controls to achieve the proposed amended emissions limit. As noted previously in the discussion of the control options, gas temperatures below 500°F would require a different, more reactive, catalyst formula than systems operating at gas temperatures above 500°F. And, as also previously stated, the only known application of a low temperature catalyst in a cement plant application was a slip-stream pilot test which failed due to catalyst poisoning. None of the operating SCR systems in cement kiln applications operate below 550°F. Further SCAQMD acknowledges on page 1-23 of the PEA, paragraph 2, that: "..., and the presence of sulfur compounds in the exhaust gas , the optimum flue gas temperature of an SCR system is case-by-case and will range between 550 °F and 750°F to limit the occurrence of several undesirable side reactions at certain conditions." CalPortland, does not know if the vendors were made aware of the actual expected gas temperature of around 350°F or whether they would still warranty their systems to perform and achieve the proposed emissions limit at this stack condition.

4.3 Vendors not Adequately Informed Regarding SO_2 Emissions

As also discussed the effectiveness of the SO_2 control technologies proposed by Vendors 2 and 3 are questionable at the actual emissions concentrations of the gas stream. The low temperature of the gas stream, the concentration of the SO_2 in the gas stream, and the humidity/moisture content of the gas stream negatively impact the potential effectiveness of the dry scrubbing technology. First, the low temperature by itself would imply that the control efficiency would be very low. (Reference 1). Consultation with a supplier of hydrated lime indicated that optimum control efficiency for dry lime injection is impacted by both temperature and moisture content. The moisture content is the kiln gas is less than 1-3 %. Further, USEPA in their ACT for cement NO_x controls, acknowledges in Section 8.4.3 that: "Reaction kinetics decrease as the concentration of reactants decreases." In layman's terms, the molecule of pollutant must find and react with a molecule of reagent. The fewer molecules of pollutant in the gas the lower the probability that the pollutant and reagent will find each other and react. During typical operations the concentration of SO_2 in the gas is well below 10 ppm and often around 2 ppm. At these concentrations, reaction kinetics would indicate little to no impact on the SO_2 concentration from injecting dry reagent. Then the question is whether this control system would protect the catalyst during the periods when the SO_2 spikes to 1500 ppm.

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Discussions with a WGS vendor indicated that at the low typical SO_2 concentrations no reductions in the SO_2 concentration would be achieved. Further, although a WGS will reduce SO_2 down to somewhere between 5 and 12 ppm depending upon the reagent used, there would be a lag between the beginning of the spike and the time the control would effectively control the higher concentration. Discussions between CalPortland and the Vendors, where the actual typical and spike emissions rates and gas temperatures would have identified these concerns. Based upon knowledge of the gas conditions, and the operation of the proposed control technologies, CalPortland questions whether either the SO_2 or NO_x controls will perform as proposed and further questions if the Vendors would warranty them. CalPortland has no way of knowing if the Vendors were ever made aware of the range of pollutant concentrations and gas temperatures when proposing their technologies and costs.

Further, the options as proposed, do not appear to address the fact that although CalPortland would not routinely operate the kilns without operating the waste heat boilers as the boilers provide energy to either the plant or the grid and result in lower emissions, of GHG and other combustion pollutants for the required energy usage. The kilns can operate without the waste heat boilers, and in situations where a waste heat boiler (WHB) needs to be offline for repair or due to a malfunction, the kiln would not be shutdown. First, it takes significant amount of time (days rather than hours) to safely shut the kiln down. Further, because of the high temperatures within the kiln, the refractory is thermally shocked to some degree during startup and shutdown, unnecessary startups and shutdowns result in unnecessary damage to the refractory. Therefore, the NO_x control systems would need to be designed to either operate at the higher temperature when the WHB is not in operation or would need to either bypass the NOx control until gas temperatures are reduced or include mechanism to rapidly cool the gas to the acceptable range to protect the catalyst. There is no indication in either the available PEA or the ETS documents to indicate that this alternate operating scenario was contemplated. Further, from a technical perspective, the catalyst formulations are different for low temperature and the more common higher temperature applications.

4.4 Determination of BARCT

Best Available Retrofit Control Technology (BARCT) is the retrofit of an additional control technology on an existing industrial process. By the very nature of retrofit of a control versus integrating the control into the initial design of a process, and the fact that the uncontrolled emissions rates for existing, older process design are in most cases higher than those from a new process, the control technologies and the achievable emissions reductions/ emissions rates after the installation of BARCT in many instances will not achieve the emissions reductions and ultimate pollutant emissions rates from Best Available Control Technology (BACT) required for new process equipment or major modifications to existing process equipment. Therefore, BARCT should not establish an emissions limit lower, than that which would be achieved by A

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BACT for a new source. The Proposed emissions limit of 0.5 lb NO_x/T_c is 33% of the new limit established by the New Source Performance Standards (NSPS) for a new PH/PC kiln system, the only new kiln type being constructed which has a limit of 1.5 lb NO_x/Tc. A review of the RBLC indicates that the lowest BACT limit for a new PH/PC kiln is 1.4 lb NO_x/T_c and the lowest/only LAER limit for a cement kiln, also a new PH/PC kiln, is 1.2 lb NO_x/T_c. The NOx limit proposed for BARCT (0.5 lb NO_x/T_c) is approximately 60% lower than for a new kiln constructed in a non-attainment area and for a kiln type with significantly lower uncontrolled emissions rate. Establishing a BARCT limit at this level is inappropriate and not supported by practical application of the technologies or common sense.

4.5 Evaluation of Cost Effectiveness based solely on the cost per ton of pollutant removed is inappropriate for Cement Application.

Cement is a commodity product and as such pricing is competitive with competitors with the general vicinity of the cement plant as well as imports. Particularly in locations with nearby ports for imports from Asia where production costs are lower and environmental controls are less stringent. Unlike other industrial categories the high capital and annual operational costs to implement the controls proposed as necessary to achieve the unrealistic emissions limitation in the proposed amended Regulation XX cannot be recovered by increases in the price of the cement product. While as noted previously, CalPortland has serious concerns about whether the estimated capital and annual operating costs provided by the three vendors, the costs provided will result in an increase in the price of cement from the plant of as much of $10 per ton of cement or more. At this price differential, cement from CalPortland's plant will have no market.

The implementation of SNCR to the existing NO_x controls on CalPortland's Colton kilns will achieve an overall NOx reduction of approximately 75% below the uncontrolled emissions rate., This represents a control efficiency in the same range as the reported control efficiency (70-80% control) of the Joppa kiln, which is the only existing long dry kiln operating an SCR for NO_x control. Further, the resulting emissions rate achieved by the use of SNCR at CalPortland's kilns, 1.64-1.91 lb NO_x/T_c is believed to be at or below the emissions rate of the Joppa kiln.

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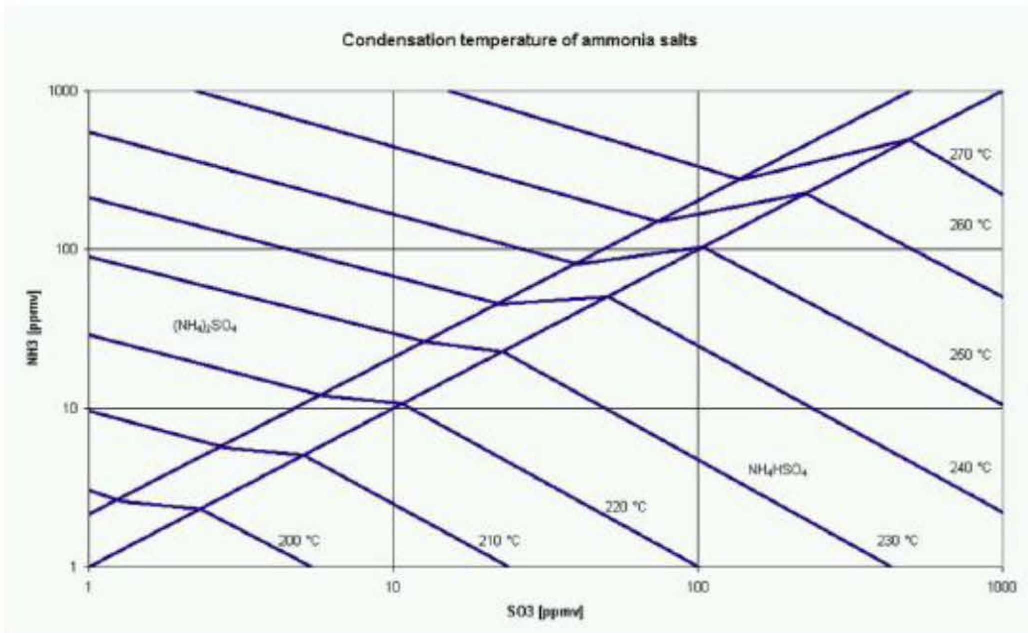
5.0 Conclusions

1. The Administrative Process for the development of the proposed emissions rate in Proposed Amended Regulation XX is flawed and did not provide CalPortland the opportunity for input to the Vendors, thereby potentially and CalPortland believes did indeed compromise the technical feasibility of the proposed control options and emissions limit. Failure to provide, at a minimum, access to the details of the design basis utilized by the vendors and the detailed cost spreadsheets and assumptions denied CalPortland the opportunity to provide fully informed comments on the proposal.
2. CalPortland, based upon knowledge of the process and gas characteristics at the Colton plant and based upon knowledge of the existing cement kiln SCR operations, does not believe that the control technologies are technically feasible or the Colton kilns.
3. CalPortland believes that the proposed emissions limit is unachievable for the long dry kilns at Colton and further that setting a BARCT emissions limit that is one third of the NSPS and BACT limits established for new preheater/precalciner kiln systems and 60% lower than a LAER emissions limit for a new kiln is inappropriate and well beyond the intent of BARCT.
4. The proposed emissions rate is technically unachievable with the proposed controls, and further will result in the inability of CalPortland's cement product to compete in a commodity market.

Appendix A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100
10
1
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210 °C
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230 °C
240 °C
250 °C
260 °C
270 °C
1
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100
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SO3 [ppmv]

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RESPONSES TO COMMENT LETTER #3
(Cal Portland Company - January 30, 2015)

On April 9, 2015, after the release of the NOP/IS for public review and comment, the Cal Portland Company (CPCC) operators surrendered their operating permits for the Portland cement kilns and have applied for Emission Reduction Credits (ERCs). Thus, because CPCC operators are no longer operating the Portland cement kilns and they no longer hold current SCAQMD operating permits for these units, the existing setting or NOx emissions baseline for the Portland cement kilns at CPCC is zero. Further, if CPCC operators decide to restart the Portland cement kilns in the future, applications for new SCAQMD permits to operate would be required. Further, these permit applications would be subject to an extensive permit review process such that that the Portland cement kilns would be treated as a new installation that would be subject to a new CEQA review and BACT requirements, instead of BARCT. In addition, CPCC would need to purchase RTCs to offset any NOx or SOx emissions as well as ERCS to offset other non-attainment pollutants as required by Regulation XIII. Because of CPCC's current permitting status for these Portland cement kilns, CPCC operators will not be able to retrofit the Portland cement kilns with air pollution control equipment in response to the proposed project without first dealing with the permitting issues for the Portland cement kilns.

Because this comment letter does not contain any CEQA-related comments, and because the CPCC facility is no longer affected by the proposed project, responses to this comment letter have not been prepared.

Comment Letter #4

Los Angeles Department of Water & Power

January 30, 2015

Ms. Barbara Radlein
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Dear Ms. Radlein:

Subject: Los Angeles Department of Water and Power's (LADWP) Comments on Notice of Preparation of a Draft Program Environmental Assessment Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

The LADWP appreciates the opportunity to provide comments on the *Notice of Preparation (NOP) of a Draft Program Environmental Assessment on the Proposed Amended Regulation XX – RECLAIM*. The LADWP remains committed to working with South Coast Air Quality Management District (SCAQMD) to further develop efficient and effective policies to reduce NOx emissions from RECLAIM facilities in order to meet the federal Ozone standards in the South Coast Air Basin.

Serving approximately 1.4 million customers in Los Angeles with a generating capacity of over 7,300 megawatts, the LADWP is the largest municipal electric utility in the nation, and the third largest electric utility in California. The LADWP is a vertically integrated utility, owning and operating a diverse portfolio of generation, transmission, and distribution assets spanning several states. As part of its modernization efforts, since the 1990's, the LADWP has been replacing its existing, less efficient utility boilers in the South Coast Air Basin with new, state-of-the-art combined-cycle and simple cycle turbine systems equipped with selective catalytic reduction technology to minimize NOx emissions. During this modernization process, the LADWP's generating facilities have been subject to New Source Review and are equipped with Best Available Control Technology, or BACT which reduces NOx emissions by at least 90 percent. 4-1

The LADWP also continues to make unprecedented investments in renewable energy resources, energy efficiency and transportation electrification to improve the

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environment. The LADWP is on track to meet 33 percent of its energy sales from renewable energy resources, has a goal to achieve 15 percent energy savings by 2020, and is continuing to implement programs to support the electrification of the transportation sector to reduce greenhouse gases and criteria pollutants, including NOx, and as a potential solution to absorb over-generation from solar renewable sources. 4-1 Concluded

Comments on the Notice of Preparation
Draft Program Environmental Assessment Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

1. Project Description Does Not Reflect Language in the Proposed Amended Rule 2002 – Allocations of Oxides of Nitrogen (NOx) and Oxides of Sulfur

   The NOP states that the project will affect the following types of equipment and process of the top NOx emitting facilities in the NOx RECLAIM program:

   - Fluid catalytic cracking units (FCCUs)
   - Refinery boilers and heaters
   - Refinery gas turbines
   - Sulfur recovery units/Tail gas treatment units (SRU/TGUs)
   - Non-refinery/Non-power plant gas turbines
   - Non-refinery sodium silicate furnaces
   - Non-refinery/Non-Power Plant internal combustion engines (ICEs)
   - Container glass melting furnaces
   - Coke calcining
   - Portland cement kilns
   - Metal heat treating furnaces

   The NOP *Technological Overview* section further states that the project will focus on reducing NOx emissions from "the major and large sources of the top emitters of NOx" for which new Best Available Retrofit Control Technology (BARCT) has been identified, but not yet applied. This description is clearly inconsistent with the proposed amendments in Proposed Amended Rule (PAR) 2002, which establishes new NOx RECLAIM Trading Credit (RTC) adjustment factors (reductions) for all affected RECLAIM facilities (including electric generating facilities) starting in year 2016. 4-2

   Notably, the proposed draft regulatory language does not explicitly state that the reductions in NOx RTC holdings would only be applied to the eleven types of equipment and processes listed in the NOP/Initial Study. Rather, the draft regulatory text on the proposed NO_x RTC adjustment is broadly written. This interpretation of the proposed regulatory language is confirmed in the NOP/Initial

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Study, which states: "It should be noted that the proposed rule language describes an evenly distributed percent of NOx RTC reductions applicable to *all* RECLAIM facilities. [emphasis added]" Thus, the proposed NOx adjustment factors in PAR 2002 would decrease the NOx RECLAIM Trading Credits (RTCs) for all RECLAIM facilities by 49% by 2020. This reduction in NO_x RTCs would apply across the board to all facilities, regardless of whether the facility operates any of the equipment or processes listed above or not. 4-2 Concluded

If the SCAQMD determines that a NO_x RTC shave is necessary, this adjustment should focus only on the eleven types of equipment or processes with newly identified BARCT and not also apply to electric generating facilities that already have reduced RTC allocations based on most current BARCT performance levels. By contrast, the expanded scope of the RTC adjustment, as proposed in regulatory text of PAR 2002, is inappropriate given that there would likely be significant impacts to other RECLAIM facilities impacted by an across-the-board shave in RTC holdings.

2. Initial Study does not address the impacts of an across-the-board 49 percent reduction in RTC holdings on energy supply

Because SCAQMD, in the NOP, did not consider the across-the-board NOx RTC reductions as proposed in PAR 2002, it did not address the potential impacts on energy supply. Reduction in allocations will create significant impacts on energy supply by restricting power generation operations. LADWP's in-basin generating facilities' would be faced with the following operational constraints and needs: 4-3

- Transmission constraints – The LADWP is currently reaching its maximum transmission system capability. As the LADWP integrates renewables in the generation mix, increased frequency of ramp-ups to mitigate variable output from renewables would lead to corresponding increases in the in-basin NOx emissions from electric generating facilities regulated under RECLAIM program. Limiting internal generation capability by the shave would require the LADWP to import power from out-of-basin generation, which could further strain the transmission system. 4-4

- Need for local generation to support local renewables - Local renewables are not reliable sources of sustained electricity and are significantly less reliable than Photovoltaic (PV) and wind projects, especially during peak periods. Due to the nature of the connection between local solar sources (*i.e.*, roof-top PV panels) and the local grid, the connection automatically disconnects during unstable voltages due to high demands by heat waves. As a result, local, dispatchable generation is very important to support local renewables. 4-5

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- Certain minimum amounts of inertia in-basin are required to import out-of-basin generation - This is a location specific requirement to maintain the stability of in-basin local transmission system as well as the entire transmission system and to smooth out the fluctuation of import of out-of-basin generation. The paradox of this requirement is as follows. The fewer generating units that are online in the basin, the less inertia (rotating mass of turbine and generator) is online. The less inertia that is online, the less transiently stable the local system will be following typical disturbances, such as transmission line short circuits that are normally cleared by very fast-acting relays and circuit breakers. The remedy for the lack of local inertia is to decrease imports into the basin from external sources. The physical paradox is the fewer generators that are on in the basin, the less one can import into the basin due to limits on imports due to transient instability. If the LADWP decreases local generation, it only decreases its ability to import. 4-6

- "Reliability Must-Run" Generation is needed in-basin - LADWP's local transmission system was never intended to be reliably operated without some local generation online. This generation is called "Reliability-Must-Run" (RMR) generation because the local transmission system can be operated in compliance with Federal and WECC reliability standards only when location-specific RMR units are in operation at minimum load levels. If the RMR generation is decreased due to lack of NOx credits, the only way to meet reliability standards under high load conditions would be to shed customer load, which is contrary to the LADWP's obligations to provide reliable supplies of electricity to our customers. 4-7

- Increased vehicle electrification will increase electricity demand – Although the LADWP's Integrated Resource Plan analyses show that LADWP's in-basin generating facility NOx emissions are projected to increase due to increased vehicle electrification, there would be a *net decrease* in NOx emissions in the South Coast Air Basin. LADWP urges SCAQMD to consider the potential net NOx reductions from transportation electrification in the design of the NOx RECLAIM program. Furthermore, the Clean Air Act (CAA or Act) allows SCAQMD to consider the offsetting NOx emission reductions from transportation electrification in developing an approvable implementation plan for the attainment and maintenance of the ozone standard. As SCAQMD has acknowledged, reaching the 2032 ozone attainment goal would require nearly complete transformation of passenger vehicles to zero-emission technologies, about 80 percent of the truck fleet to zero- to near-zero technology, and nearly all locomotives operating in the South Coast Air Basin to be using some form of zero-emission technology. In addition, Governor Brown's State of the State speech includes reducing today's petroleum use in cars and trucks by up 4-8

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to 50 percent. This means that the only way for the State to achieve the Governor's goal, as well as the air goal goals under the CAA, is for SCAQMD to develop regulatory policies that allow for increased generation (and thereby emissions) from electric generating facilities in order to supply the necessary energy for electrifying the transportation sector. 4-8 Concluded

Alternative Regulatory Approaches

In the event that SCAQMD decides to impose an across-the-board RTC reduction on all affected RECLAIM facilities (including electric generating facilities), LADWP urges the SCAQMD alternatives to minimize the regulatory impacts of that RTC adjustment on the electric power sector. The development of such a regulatory alternative is appropriate given that affected electric generating units already meet the proposed BARCT based on SCAQMD's own analysis. Furthermore, additional reduction in NOx emissions at in-basin plants may not be feasible due to the fact that the only way to achieve additional reductions from these well-controlled plants is by reducing their generation output. As discussed above, reducing the utilization of in-basin gas-fired generation is not a viable option given the essential role these units play in ensuring a reliable supply of electricity in the basin. 4-9

The LADWP has identified a possible regulatory credit mechanism that could be developed to ensure that affected power plant facilities would not be penalized for increased NOx emissions resulting from an increased demand in electricity due to native load needs and increased transportation electrification. Such a crediting mechanism would incentivize the development and implementation of renewable energy and transportation electrification. This approach would be consistent with SCAQMD's position as described in its comment letter to U.S. Environmental Protection Agency (EPA), which states that "It is important that the 111(d) regulation recognizes California's unique situation and does not hinder the introduction of additional renewable energy generation." "The proposed regulation must be structured to support clean generation and renewable energy."[1] 4-10

The policy to be addressed is similar to the Clean Fuels Adjustment provision in that "Allocation adjustments are warranted because of the significant emission decreases that will be realized from mobile sources."[2] Thus, there is a precedent where SCAQMD has allowed RECLAIM affected entities to have sufficient RTCs for increased NOx emissions in the South Coast Air Basin decrease in order to

[1] November 26, 2014 letter to EPA regarding *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units – Proposed Rule*

[2] RECLAIM Rules staff report, October 1993, p. 2-19

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ensure attainment and maintenance of the ozone and other ambient air quality standards. Similarly, the purpose of this alternative approach would be to ensure sufficient RTCs are available for affected electric generating facilities to support the planned levels of transportation electrification that are necessary for achieving the air quality standards, as well as operate its in-basin generating stations to meet native load needs.

The California Air Resource Board's (CARB) Phase II reformulated gasoline production and federal Clean Fuel requirements adopted in the early 1990s require that cleaner burning fuel for automobiles be sold in California. The SCAQMD determined that the modifications to the refining facilities in California would be necessary to produce the reformulated gasoline. These plant modifications would result in emissions increases but the emissions increases would be offset more by mobile source reductions from the use of cleaner fuels by vehicles in the same air shed. As a result, SCAQMD developed criteria to allow for the emission increases while providing an upper bound of RTC allocations. Refinery owners could request an increase in RTC allocations when submitting an application for a permit amendment.

4-10 Continued

The Clean Fuels Adjustment provision establishes helpful precedent for SCAQMD providing flexibility in the implementation of the RECLAIM Program. The discussion below describes how a similar credit mechanism might be developed to ensure affected electric generating facilities had sufficient RTCs in the event that SCAQMD decides to impose an across-the-board RTC reduction on all affected RECLAIM facilities.

1. <u>Quantify the amount of RTCs needed to support native load and transportation electrification.</u>

The first step of the process would involve each affected electric utility quantifying the amount of NOx RTCs that it would need to cover its projected NOx emissions. The process for calculating each unit's generation level would be based on the amount of electricity that the utility would need to generate in order to meet its native load, along with the expected electricity demand increase resulting from the transportation electrification. This determination would likely be based on the Integrated Resource Plan (IRP) or similar process for estimating the utility's native load and the expected transportation electrification for the next 10 to 15 years. With respect to transportation electrification, the utility would need to work with the SCAQMD and CARB to estimate the expected number of electric vehicles (EVs) in the basin in order to determine the increased electricity demand resulting from electrification of the transportation sector.

Based on this quantification of future electricity demand and NOx emissions (which could be updated on an annual basis), the SCAQMD would allow the

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affected electric utilities to hold in their accounts sufficient number of NOx RTCs to cover their emissions on a system-wide basis. This amount of each utility's RTCs would not be deducted from its RECLAIM account and consequently remain available for use in meeting its RECLAIM credit-holding requirements.

2. Determine the amount of RTCs used for transportation electrification.

   Each utility sector would quantify the number of RTCs that are actually used to generate electricity for vehicle electrification. This quantification would be performed for each compliance year based on a method similar to CARB's Low Carbon Fuel Standard approach. A combination of meter kWh data and estimated kWh data applied to the number of EVs that a utility reports would be used to quantify the emissions due to the increase in electricity demand from electric transportation.

3. Label unused RTCs designated to cover transportation electrification as non-tradable.

   The RTCs that an electric utility retains based on the quantification of future electricity demand due to transportation electrification would be put into a utility's account and labeled non-tradable. The non-tradable RTCs could be used for compliance purposes only and allocated tradable RTCs would be used first for compliance. Thus, if a utility has NOx emissions that are lower than expected such that its non-tradable RTCs are unused, the utility would not be able to sell them to entities outside of the utility's system. At the end of the reconciliation period, the utility would surrender unused non-tradable RTCs to SCAQMD for credit toward reducing NOx emissions through the RECLAIM program and meeting attainment of the ozone standard. 4-10 concluded

State Implementation Plan crediting with respect to design of the NOx RECLAIM program to accommodate transportation electrification

There are uncertainties with respect to the level of transportation electrification and the level of in-basin generation needed to support future renewables which creates uncertainties as to the number of RTCs that electric generating facilities would need. LADWP believes that SCAQMD has the discretion to develop its NOx RECLAIM program to accommodate such uncertainties without having to determine the exact amount of the NOx reductions upfront for SIP credit purposes. LADWP is ready and willing to work with SCAQMD, CARB, and EPA to explore opportunities in creating an approach to include the benefits of transportation electrification as well as support clean generation and renewable energy.

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Comments of Proposed Amended Rule 2012 – Appendix A: Protocol for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) – Attachment C – Quality Assurance and Quality Control Procedures

Section (B)(2) – LADWP supports SCAQMD's efforts to allow postponement of a RATA when a major source is physically incapable of being operated.

Section (B)(2) requires that a relative accuracy test audit (RATA) be performed on a major source on a semi-annual or annual basis within a specified time period. For example, the semi-annual assessment is required to be completed within six months of the end of the calendar quarter in which the continuous emission monitoring system (CEMS) was last tested for certification purposes or within three months of the end of the calendar quarter in which SCAQMD sent notice of a provisional approval for a CEMS, whichever is later. This requirement currently does not provide NOx RECLAIM facilities with the flexibility to reschedule a RATA when a unit is inoperable due to unexpected unit shutdowns or delays in completing unit's scheduled maintenance and repair. When this happens, the RECLAIM operator must seek a variance from the SCAQMD Hearing Board. LADWP supports SCAQMD's efforts to address these situations in Section (B)(2) to allow postponement of a RATA when the major source "is physically incapable of being operated."

The LADWP has experienced situations where its generating units were shut down due to unit damage or unexpected delays encountered during scheduled maintenance and repair of a unit. In such situations, LADWP's generating units were incapable of being operated at the time of the mandated RATA test. For example, in October 2013, LADWP's Haynes Unit 9 combustion turbine was operating at full generation capacity when it came to an abrupt stop; it was determined that the compressor section of the turbine was damaged such that procurement of replacement components and repair required several months. The unit's RATA was scheduled for early November 2013 to meet the December 31, 2014 regulatory deadline but could not be performed due to the length of time required to repair the unit. Although SCAQMD does allow postponement of a RATA for an "intermittently operated source" under Section (B)(2)(h), the provision is narrowly defined. In LADWP's case as described above, SCAQMD's regulatory requirements did not allow reschedule of the RATA. Because of the inflexibility with respect to reschedule of the RATA, LADWP needed to seek a variance from the SCAQMD Hearing Board. Thus, SCAQMD's efforts to postpone a RATA to address the situation where the major source is physically incapable of being operated would allow facilities to focus on bringing the unit back in operation rather than spending significant

4-11

staff and Hearing Board time in the variance process for situations where there are no adverse air quality impacts. 4-11 Concluded

Section (B)(2)(c) and (B)(2)(d) Due Date for RATAs

The LADWP has the following concerns with the proposed language in this section:

- With respect to rescheduling of a RATA, there is inconsistent treatment between electrical generating facilities that only operate under a California Independent System Operator (Cal ISO) contract and those generating facilities such as LADWP's that do not. Generating facilities only operating under a Cal ISO contract would be able to postpone the due date for a RATA to the next calendar quarter whereas LADWP's generating facilities would not. If LADWP encountered a situation as described above where the unit is physically incapable of being operated, it would be able to postpone the RATA only to within 14 unit operating days from the first re-firing of the unit. It is unclear why there is inconsistent treatment when electrical generating facilities, whether they have a Cal ISO contract or not, face similar operational issues. 4-12
- The proposed 14 unit operating day window of time for conducting a RATA in the case where a major source is physically incapable of being operated is insufficient at LADWP generating facilities when a unit is inoperable for an extended period of time. Before a RATA can be performed, the LADWP must perform a series of tests to ensure reliable and safe operation of the unit. Tests to balance the turbine rotor and generator rotor must be performed when there is a repair that lasts longer than several months to ensure that the unit operates within the Original Equipment Manufacturer vibration limits. It may take several sets of these "balance shot" tests before the unit is operating within vibration limits and each balance shot typically takes several days to a week to complete. Based on LADWP's experience, we recommend that SCAQMD allow postponement of the due date for a RATA to the next calendar quarter similar to Section (B)(2)(d) or 30 unit operating days in order to safely conduct the tests and operate the unit and avoid the risk of damaging the unit. This 30-day extension is similar to the provision in 40 CFR Part 75, Appendix B. Section 2.3.3 in which EPA provides a 720-operating hour grace period if RATA cannot be performed on the due date. 4-13

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Section (B)(2)(c)(i) and (ii) – Proposed requirement to disconnect and flange the fuel feed lines when a unit is physically incapable of operation is unnecessary and costly

The proposed language requires that:

i. All fuel lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and
ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

The proposed requirement to disconnect and flange the fuel feed lines would be costly and a significant task requiring scaffolding, crane support, procurement of equipment, and staff/labor time from pipefitters, welders, maintenance mechanics, pressure vessel group inspectors, engineering, drafting and operations. This requirement would unnecessarily create a significant health and safety risk if the fuel lines are insulated with asbestos-containing materials (ACM). The intact ACM would have to be removed to gain access to the fuel pipelines which would be against the general plant operating and maintenance best practices to leave intact ACM alone. This requirement would also take several weeks in order to procure the necessary materials and to complete construction. Since the fuel meters would be required to be maintained and associated fuel records be kept, SCAQMD would already have two sources of data as a check that the source is not operating. Thus, LADWP urges SCAQMD to delete Section (B)(2)(c)(i). 4-14

Again, the LADWP appreciates the opportunity to provide comments on the NOP. We would urge that LADWP and other stakeholders be provided a reasonable schedule for further development of any rule changes to RTC allocations that is consistent with the regulatory requirements and provides a reasonable opportunity for stakeholder review and comment. 4-15

If you have any questions or would like additional information, please contact Ms. Jodean Giese of my staff at (213) 367-0409.

Sincerely,

Mark J. Sedlacek

Mark J. Sedlacek
Director of Environmental Affairs

LL/JG:mg
c: Ms. Elaine Chang, SCAQMD
Mr. Joe Cassmassi, SCAQMD
Mr. Gary Quinn, SCAQMD
Ms. Jodean M. Giese

RESPONSES TO COMMENT LETTER #4
(Los Angeles Department of Water and Power - January 30, 2015)

4-1 This introductory comment summarizes the commentator's facilities, customer base, generating capacity, and control equipment and explains that this comment letter has been submitted in response to the proposed amendments to Regulation XX and the associated NOP/IS. Responses to specific concerns are presented in Responses to Comments 4-2 through 4-21.

4-2 This comment states that there is an inconsistency between the project description in the NOP/IS which focuses on achieving NOx emission reductions from the top emitting NOx RECLAIM facilities compared to the proposed rule language which shows a 50 percent shave across all NOx RECLAIM facilities. Further, this comment claims that the proposed rule language does not explicitly state that reductions in RTC holdings would only be applied to the 11 types of equipment/processes that are identified in the NOP/IS. This comment requests the shave, if determined by the SCAQMD to be necessary, to only focus on the 11 types of equipment/processes that are identified in the NOP/IS and not apply to electric generating facilities that already have reduced RTC allocations based on the most current BARCT performance levels.

Since the release of the NOP/IS, the proposed project has been modified to apply a shave to the holders of the top 90 percent of RTCs. However, it is likely that the required reductions will be obtained from the installation of NOx control equipment at 20 facilities, as well as from RTCs that are in the program but are being used for compliance purposes. Since only the installation and operation of NOx control equipment would have environmental impacts, the CEQA analysis focuses on these impacts. If some facilities purchase RTCs to meet their allocation targets, this will not have an additional environmental impact but will be considered in the socioeconomic analysis.

4-3 This comment claims that because the NOP does not consider an across the board shave that would affect more than 11 categories of equipment/processes as is proposed in PAR 2002, the NOP did not address the potential impacts on energy supply and the operational constraints on in-basin electrical generating facilities.

Contrary to the comment, the NOP/IS identified energy, including impacts on energy supply, as one of the environmental topic areas that may be adversely affected by the proposed project. PAR 2002 has been revised and the project description in the Draft PEA now correlates to the rule language. The proposal includes an adjustment account specifically for power generating facilities. The RTCs in this account could be accessed in the event of a power generation emergency declared by the Governor.

4-4 This comment states that the commentator's facilities are reaching the maximum transmission capability and limiting the internal generation capability as a result of the NOx shave would require power to be imported from out-of-basin generation, which could further strain the transmission system. This comment also claims that the increased reliance on renewable sources of energy with variable outputs will cause an increased frequency of ramp-ups and increased in-basin NOx emissions from electric generating facilities.

SCAQMD staff acknowledges that during times when maximum transmission capability is reached, there will be a need for peaker plants to ramp-up and there will be increases in emissions as a result. Staff does not believe transmission limitations will be significantly affected because the rule proposal provides a mechanism for access to additional RTCs if needed by power plants.

4-5 This comment maintains that local renewables are not reliable sources of sustained electricity and local, dispatchable generation is very important to support local renewables. For example, the connection between local solar sources and the local grid is automatically disconnected when there are unstable voltages due to high demand during heat waves.

SCAQMD staff acknowledges that there is a need to access local renewable sources of energy. The rule proposal has been modified to help generators ensure this availability.

4-6 This comment claims that there are certain minimum amounts of inertia in-basin that are required to import out-of-basin generation such that when fewer generators are operating in the basin, a lesser amount of electricity can be imported into the basin.

The staff proposal has been modified to allow needed generation for local inertia requirements.

4-7 This comment claims that if local electricity generation or "Reliability-Must-Run (RMR) is decreased due to a lack of NOx credits, the only way electricity demand can be met under high load condition would be shed customer load, which is contrary to the LADWP's obligations to provide reliable supplies of electricity to its customers.

The staff proposal has been modified to allow meeting electricity demand under high load conditions.

4-8 This comment claims that because increased vehicle electrification will increase electricity demand causing an increase in NOx created for electricity generation but decreasing overall NOx because electric vehicles will no longer be combusting fuel. This comment also claims that the SCAQMD should develop regulatory policies that allow for increased generation and increased emissions from generation in order to supply the necessary energy for electrifying the transportation sector.

Increased demand due to transportation electrification will occur gradually and will be monitored by staff. If such demand requires rule amendments, there will be time to implement them.

4-9 This comment requests the alternatives in the PEA minimize the regulatory impacts of the RTC shave on the electric power sector if there is an across the board shave for all facilities in the program.

The staff proposal does not recommend an across the board reduction for all facilities. The proposal contains a 47 percent NOx RTC shave on power plants and an adjustment account that could be accessed by power plants if the Governor declares an emergency that would require additional power generation. In addition, the PEA analyzes multiple alternatives, each with a varying NOx RTC shave on power plants. For example, Alternative 1 proposes a 53 percent NOx RTC shave on power plants and Alternative 2 proposes a 60 percent NOx RTC shave on power plants. In addition, of the shaves proposed, Alternative 3 contains the smallest shave percentage for power plants at 36 percent. In addition, the No Project alternative, Alternative 4, does not propose a NOx RTC shave on any facility, including power plants.

4-10 This comment suggests that a credit mechanism should be developed to ensure that affected electric generating facilities have sufficient RTCs if the SCAQMD proposes an across the board RTC shave. The example cited is the Clean Fuel Adjustment credits that have been available to refineries for the production of reformulated gasoline.

In response to the comment, the staff proposal would not be an across the board shave. The staff proposal would establish a separate adjustment account to hold RTCs for power plants to meet their NSR holding obligations. Many newer, peaking plants are required to hold RTCs at the potential to emit level each year even though their actual emissions are far below this level. The adjustment account would relieve power producing facilities from the obligation of purchasing RTCs in order to meet the NSR holding requirements of Rule 2005. RTCs either held or purchased by a facility would be for the purpose of reconciling annual emissions. Furthermore, if the demand for power results in a severe shortage that would lead to the state Governor declaring a state of emergency, a power producing facility would be able to access the adjustment account for non-tradable credits for offsetting annual emissions. The adjustment account would take the shaved RTC amount for the given compliance year according to the implementation schedule in the rule; each year would be an increment of the overall 47 percent shave.

The comment states that there would be increased demand due to increased transportation electrification and renewable power. If this power demand translates into an RTC demand, these credits would be purchased from the NOx RECLAIM market. If there is a shortage of credits which would result in an increase in the RTC price, a safety valve in the rule would provide access to non-usable, non-tradable credits in the event that the market price for discrete year credits rises above $15,000 per ton.

4-11 The comment expresses support regarding SCAQMD’s efforts to allow a postponement of a RATA when a major source is physically incapable of being operated.

SCAQMD staff acknowledges your support for the proposed amendments in Rule 2012.

4-12 This comment claims that there are inconsistencies in how electrical generating facilities that only operate under a California Independent System Operator (Cal ISO) and how generating facilities operated by the commentator are treated when rescheduling a RATA.

Staff has revised the proposed rule language to include power plants operated by municipalities.

4-13 This comment claims that the proposed 14 unit operating day window of time for conducting a RATA where a major source is physically incapable of being operated is insufficient at the commentator's generating facilities when a unit is inoperable for an extended period of time. This comment recommends a postponement of the due date for a RATA to the next calendar quarter or 30 unit operating days.

Discussion with the commenter revealed that the concern here has to do with the potential for sequential equipment failures. However, the 14 unit operating day RATA extension being proposed would apply separately for each independent failure. That is, if equipment operating under the 14 operating day RATA postponement provision should experience an unrelated failure prior to successfully completing a RATA, the 14 day clock would restart. The staff report provides clarification on this point. Furthermore, an extension duration of 14 operating days is consistent with the existing provisions pertaining to the timing of RATA for CEMS on a stack or duct through which no emissions have passed in two or more successive quarters in Attachments C to Rules 2011 and 2012 and with variance conditions established by the SCAQMD Hearing Board in previous cases. Conversations between SCAQMD staff and facility operators also indicate that fourteen operating days provide sufficient time to conduct a RATA in such cases.

4-14 This comment requests deletion of the proposal to disconnect and flange the fuel feed lines because it would be a costly and a significant task involving construction workers and equipment and would create significant health and safety risks if fuel lines are insulated with asbestos-containing materials.

RECLAIM has existing provisions that address non-operated major SOx and NOx sources in Rule 2011 (c)(10) and Rule 2012 (c)(9), respectively. These requirements are imposes when the period of non-operability is relatively long. These provisions both require the operator to "disconnect fuel feed lines and place flanges at both ends of the disconnected lines." Similarly, Rule 2011 (c)(9) addresses infrequently-operated major SOx sources. One of the requirements with which a source must comply to be eligible to be an infrequently-operated major SOx source is that the "Facility Permit holder shall disconnect fuel or process feed line(s) and install, maintain, and operate a monitoring device, which has been approved by the Executive Officer, to provide a continuous positive indicator of the operation status of the source to the remote terminal unit (RTU) for the purposes of demonstrating the source is not operating and for preparing emissions reports." Collectively, the requirements of Rule 2011 (c)(9), Rule 2011 (c)(10), and Rule 2012 (c)(9) establish the appropriate precedents for the steps a facility must take to qualify for a reduced level of emissions monitoring of a major source that is out of operation for an extended period. In addition, the comments have not included any examples to demonstrate cases where disconnecting sections of fuel line is infeasible. Therefore, the proposed rule language's eligibility requirements for delaying RATA testing to the end of the next quarter of both disconnecting fuel lines and maintaining and operating the fuel meters are appropriate and consistent with existing, related provisions.

4-15 This comment expresses appreciation for the opportunity to provide comments on the NOP and requests a reasonable schedule and an opportunity to comment on rule development changes to RTC allocations.

SCAQMD staff appreciates the comments and input. All affected stakeholders will be notified of any changes and SCAQMD staff will continue to meet regularly with the stakeholders, which includes the commentator, to solicit input.

Comment Letter #5

CHARLES F. TIMMS, JR.
ATTORNEY AT LAW

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January 30, 2015

BY EMAIL (BRADLEIN@AQMD.GOV) AND U.S. MAIL

Barbara Radlein (c/o CEQA)
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4178

Re: Comment Letter on Notice of Preparation of a Draft Program Environmental Assessment--Proposed Amended Regulation XX; City of Burbank, Department of Water and Power

Dear Ms. Radlein:

The City of Burbank, Department of Water and Power ("the City") appreciates the opportunity to present the following comments on the Notice of Preparation ("NOP") of a Draft Program Environmental Assessment on Proposed Amended Regulation XX. The comments address the need to evaluate potential adverse impacts of a proposed reduction of approximately 50% of each facility's NOx RECLAIM Trading Credits ("RTCs") ("NOx Shave"). The City operates two facilities regulated under the RECLAIM: its own power plant operated by its Department of Water and Power ("BWP") and the Magnolia Power Plant ("MPP"), a facility owned by the Southern California Public Power Authority ("SCPPA") but also operated by BWP. 5-1

SUMMARY

If power plants are subject to a 50% NOx Shave, as set forth in the draft rule attached to the NOP, then they may be operated less frequently due to the higher costs that the shave imposes. Their electricity production may be shifted to other, more polluting power plants, with adverse air quality impacts where those other power plants are located. The District must evaluate these potential adverse air quality impacts in the Environmental Assessment for the 5-2

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proposed NOx RTC shave, whether those impacts occur inside or outside the South Coast Air Basin. In addition, the District should analyze two alternative projects that may mitigate or eliminate these potential adverse impacts but still allow the project to achieve its basic objectives: (1) the alternative of no reduction of NOx RTCs for any power plant that already operates with either Best Available Control Technology ("BACT") or Best Available Retrofit Control Technology ("BARCT") installed, and (2) the alternative of a smaller reduction of, for example, 25% of each such power plant's NOx RTCs. 5-2 Concluded

ADDITIONAL DETAIL

Most of the power plants that would be subject to a 50% NOx shave are gas-fired peaking plants with BACT or BARCT already installed and NOx emissions in the range of 2-5 ppm. These power plants could not achieve cost-effective reductions of NOx emissions in response to a NOx shave. Instead, they would have to purchase more RTCs to maintain or increase their electricity production. If they are facilities that were newly-constructed under RECLAIM (Rule 2005), they also would have to purchase RTCs to cover their PTE at the start of each compliance year. 5-3

RTC purchases in response to the shave would increase the operating costs of these power plants. The increased costs may make it economical for the operators of these power plants to reduce their level of operation and purchase replacement power from other facilities outside the South Coast Air Basin. These other facilities likely have NOx emissions rates higher than the emissions rates of the power plants subject to the NOx shave. Therefore, NOx emissions per MWhr, and overall NOx emissions from power plants, may actually increase due to the shave. But these increased NOx emissions would occur mostly in areas outside of the South Coast Air Basin. The District must evaluate these potential adverse air quality impacts. 5-4

For example, we estimate that, in response to a 50% NOx RTC shave, MPP may have to spend as much as $17 million between 2018 and 2023 to maintain its NOx RTC allocation and cover its PTE at the beginning of the compliance year, assuming no increase in capacity factor. This cost could be reduced somewhat if the District made RTCs available to MPP on a temporary basis to cover its PTE at the beginning of the compliance year, thus making it unnecessary for MPP to purchase these RTCs. These costs assume that RTC prices rise to a level comparable to the last time there was a NOx shave, in 2005 ($250/lb of so-called "perpetuity RTC"). This increase in MPP's operating costs could result in a shift of production to power plants outside of the South Coast Air Basin that do not bear these same increased costs.

In addition to evaluating these potential adverse air quality impacts in areas where emissions would increase under the proposal in the NOP, the District should also evaluate two alternatives that may reduce any potential adverse air quality impacts identified in the environmental assessment but still allow the project to achieve its basic objectives. One alternative is no reduction in RTC allocation for any power plant that already operates with either BACT or BARCT installed. A second alternative is to reduce each such power plant's RTC 5-5

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allocation by a smaller amount than the amount proposed in the NOP, such as a 25% reduction. Under both of these alternatives, facilities that have not yet achieved BARCT could have their NOx RTCs shaved by whatever percentage is needed to achieve the emissions reductions in the proposal, without asking power plants to help pay for those reductions by having their own RTC allocations shaved. 5-5 Concluded

We appreciate your consideration of our comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

RESPONSES TO COMMENT LETTER #5
(Charles F. Timms, Jr. on behalf of
City of Burbank Department of Water and Power - January 30, 2015)

5-1 This introductory comment explains that this comment letter has been submitted on behalf of the City of Burbank Department of Water and Power in response to the CEQA document and proposed shave for the proposed project. Thus, responses to the specific concerns are presented in Responses 5-2 through 5-5.

5-2 This comment suggests that the Draft PEA should evaluate the adverse environmental effects that the 50 percent NOx shave will have on power plants due to higher costs that will cause electricity production to drop and the possible shift to producing electricity from other, more polluting power plants, located either inside or outside the South Coast Air Basin (SCAB). This comment also suggests that the Draft PEA should analyze at two alternatives, as follows: 1) not imposing a shave on any power plant that already operates with BACT or BARCT; and, 2) a smaller reduction than a 50 percent shave, such as a 25 percent shave, on power plant NOx RTCs.

Regarding the comment relative to increased costs that would cause production to drop, SCAQMD staff understands that the power producers can pass costs on to consumers, so there would be no need to reduce local generation.

With regard to comment relative to alternatives, a full range of alternatives have been developed and analyzed in Chapter 5 of the PEA. Alternative 4, the no project alternative, does not impose a NOx RTC shave on any RTCs held by power plants. The proposed project would apply a 47 percent NOx RTC shave to power plant RTC holdings. When compared to the proposed project, Alternative 3 contemplates a lesser NOx RTC shave to power plant holdings of 33 percent. The two alternatives suggested by the commentator are within the range of the existing alternatives of this PEA, so specific additional alternatives are not necessary.

5-3 This comment claims that most of the power plants that would be subject to the shave are gas-fired peaking plants with BACT or BARCT already installed. This comment further claims that power plants would need to purchase more RTCs to maintain or increase electricity production levels.

SCAQMD staff acknowledges the unique situation that power generators have with regard to operating at BARCT or BACT and the requirement for RTC holdings for New Source Review (NSR) purposes. The project now contains a proposal which establishes an adjustment account which would contain the shaved RTCs from new power producing facilities for the purposes of satisfying the NSR requirements. Most power plants emissions are much less than their potential to emit, so this provision will help reduce the amount of RTCs that power plants will need to hold.

5-4 This comment claims that RTC purchases in response to the shave would increase power plant operation costs and would reduce local generation but increase NOx emissions from other power plants transmitted to the municipal utilities. The comment claims that the increase in power plant NOx emissions would be generated outside of the South Coast Air Basin and that the District should evaluate these impacts.

A sector-specific approach has been proposed with the establishment of an adjustment account. Power producing facilities would meet the NSR holding requirements without purchasing credits with this adjustment account. RTCs in this account would only be made usable for compliance with annual emissions if California's governor declares a state of emergency.

In the Draft PEA, an energy analysis was conducted and an estimated increase of electricity demand was provided in Subchapter 4.3 – Energy of this PEA. From the estimated increased electricity demand, increases in both criteria pollutants and GHG emissions were quantified for the affected facilities in Subchapter 4.2 – Air Quality and Greenhouse Gases in this PEA.

5-5 This comment duplicates the suggestions expressed in Comment 5-2. See Response 5-2.

Comment Letter #6

California Council for Environmental and Economic Balance

Southern California Air Quality Alliance

Regulatory Flexibility Group

WSPA Western States Petroleum Association

30 January 2015

Dr. Elaine Chang
Deputy Executive Officer, Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: INDUSTRY COMMENTS ON THE NOTICE OF PREPARATION (NOP) OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

Dear Dr. Chang:

These comments are presented on behalf of the members of leading Southern California businesses represented by the California Council for Environmental and Economic Balance ("CCEEB"), the Regulatory Flexibility Group ("RegFlex"), the Southern California Air Quality Alliance ("SCAQA"), and Western States Petroleum Association ("WSPA"). The members of these business groups are major Southern California employers who own and operate facilities in the Regional CLean Air Incentives Market ("RECLAIM") program. 6-1

This "Industry RECLAIM Coalition" formally offers the following comments on the Notice of Preparation and Initial Study for the Draft Program Environmental Assessment ("PEA") for Proposed Amended Regulation XX ("NOP/IS"). [1]

1. *The PEA Project Description should specify the potential shave as a range since neither the Proposed Amended Rule nor the Staff's Technical Report is complete.*

The Project Description presented in the NOP and Initial Study ("NOP/IS") incorporates Proposed Amended Rule (PAR) 2002 language as presented in Appendix A of the NOP/IS. At the time of the NOP/IS release, the AQMD had not completed technical work on this rulemaking, with the third-party consultant reviews having not even been released. The cover page for NOP/IS Appendix A did include the following disclaimer: 6-2

> *"The BARCT evaluation and the RTC shaving methodology are ongoing, so a RECLAIM industry's required RTC shave may change due to the public review process. The*

[1] SCAQMD, Notice of Preparation (NOP) of a Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014.

Dr. Elaine Chang, SCAQMD
30 January 2015

programmatic RTC shave could range from five to 14 tons per day. To provide a worst case scenario of adverse environmental impacts, the adjustment factors and the Non-tradable/Non-usable NOx RTC adjustment factors in Proposed Amended Rule 2002 subparagraph (f)(1)(B) reflect an RTC shave at the higher end of the range to capture a conservative estimate of potential control technologies needed that could generate secondary environmental impacts. As the staff proposal is being refined, if a lesser RTC shave is proposed, the adverse environmental impacts would be less and the Draft PEA and its alternatives will also be further defined."[2]

Now that the third-party contractor reviews have been released, we expect changes are needed to the technical analysis which would alter the technical calculations. Members of this coalition have unresolved questions and concerns about those reviews and the current analysis from AQMD staff. But these reviews and additional inputs from industry stakeholders will necessitate revisions to the draft PAR 2002 language, and more changes will undoubtedly be needed as the rulemaking process progresses. 6-2 Concluded

For this reason, we recommend that the PEA Project Description should explicitly specify the potential shave under this rulemaking as a range. This could be accomplished using language similar to that which was presented on the NOP/IS Appendix A cover page, however this disclosure should be noted in the Project Description section of the main PEA document; not left only in an Appendix.

2. *The PEA should explicitly address at least two project Alternatives: (1) AQMP control measure CMB-01 as approved by the Governing Board (i.e., shave of 3-5 tpd); and (2) the Industry RECLAIM Coalition proposal.*

Under the 2012 Air Quality Management Plan ("AQMP"), the Governing Board approved control measure CMB-01 which authorized further reductions from the NOx RECLAIM program. The control measure authorized by the Governing Board was based on a range of 3-5 tons per day ("TPD") of RECLAIM Trading Credits ("RTCs") being removed from the program. While stakeholders understood the eventual rulemaking could differ, the current Staff proposal as presented in the NOP/IS would be substantially larger at nearly 13 TPD. 6-3

This Industry RECLAIM Coalition has presented an alternative methodology for demonstrating command-and-control equivalency. The Industry proposal would reduce the program's quantity of RTCs by limiting the "shave" to only those reductions that can be directly attributed to the advancement of Best Available Retrofit Control Technology ("BARCT"). This Industry proposal could also result in RTC reductions greater than the approved AQMP control measure, but less than those which have been presented by the AQMD Staff.

We recommend that both of these alternatives should be fully considered as project Alternatives in the PEA, at a minimum.

[2] SCAQMD, NOP/IS for Proposed Amended Regulation XX, Appendix A, 4 December 2014.

Dr. Elaine Chang, SCAQMD
30 January 2015

3. *Public stakeholders should be provided a schedule that is consistent with regulatory requirements while providing reasonable opportunity for stakeholder review and comment.*

The proposed rulemaking could potentially result in significant economic impacts to Southern California businesses and the regional economy. The technical analysis for this rulemaking is not yet complete, and the potential impacts have not yet been fully analyzed or considered. To date, only preliminary technical data has been made available to stakeholders. As such, thorough review and input by the RECLAIM Working Group or other stakeholders has not been possible. 6-4

This Industry RECLAIM Coalition respectfully requests that stakeholders be provided with a rulemaking schedule, including this PEA and the socioeconomic analysis, that is consistent with applicable regulatory requirements but also provides stakeholders a reasonable opportunity for review and comment of the technical bases.

The RECLAIM program remains vitally important to the health of Southern California's economy and environment. The members of this coalition have actively participated in this rulemaking through the NOx RECLAIM Working Group over these last two years, and we look forward to continuing to work with you and the District's Staff on the significant rulemaking. 6-5

Very truly yours,

Bill Quinn
California Council for Environmental and Economic Balance

Michael Carroll
Regulatory Flexibility Group

Curtis Coleman
Southern California Air Quality Alliance

Patty Senecal
Western States Petroleum Association

RESPONSES TO COMMENT LETTER #6
(California Council for Environmental and Economic Balance et al - January 30, 2015)

6-1 This introductory comment explains that this comment letter has been submitted on behalf of multiple business groups that own and operate RECLAIM facilities in response to the CEQA document for the proposed project. Thus, responses to the specific concerns are presented in Responses 6-2 through 6-5.

6-2 This comment suggests that the project description in the Draft PEA should specifically describe the potential shave as a range in the same manner as the disclosure language inserted in Appendix A before PAR 2002. Since the proposed amended rule language and corresponding staff report were not complete at the time the NOP/IS was released for public review due to pending third-party consultant reviews and now that the third-party consultant reviews have been released, the technical analysis along with the proposed rule language is expected to change and as such, the Draft PEA should also reflect these changes.

The contractor's assessments were considered in the staff proposal in the Preliminary Draft Staff Report, which is the project analyzed in this PEA. The alternatives in the PEA include a No Project alternative and other alternatives that include a range of emission reductions.

6-3 This comment suggests that the Draft PEA should analyze at least two alternatives to the project. The first alternative should analyze a shave ranging from three to five tons per day in accordance with AQMP control measure CMB-01. The second alternative should analyze the "Industry RECLAIM Coalition" proposal which would limit the shave to only reductions that can be directly attributed to BARCT.

It is not necessary to add these specific alternatives because the ranges are included within the alternatives for the PEA. SCAQMD staff has included Alternative 3, the Industry Proposal, in the Draft PEA analysis. Staff did not explicitly analyze a three to five ton shave alternative as this would be between Alternative 3 and the No Project alternative (Alternative 4).

6-4 This comment is requesting a rule development schedule, to include the PEA and socioeconomic analysis, in order for public stakeholders to provide a reasonable opportunity for review and comment. This comment claims that the technical analysis for this rulemaking is not complete and only preliminary technical data has been made available to stakeholders. This comment claims that stakeholders have not been able to provide a thorough review and input. This comment claims that potential impacts have not been fully analyzed or considered.

Rule development efforts for the proposed project were initiated over two and a half years ago when staff presented basic concepts to the NOx RECLAIM Working Group on January 31, 2013. Since the January 31, 2013 Working Group Meeting, staff has held 11 additional Working Group meetings at which members were given multiple and ample opportunities to provide comments. For example, in March 2013, equipment with the highest potential for achieving NOx emission reductions was presented to Working Group members. Then, in September 2013, a preliminary assessment quantified potential NOx emission reductions and detailed survey results. In October 2013, third party contractors conducted site visits and reviewed staff's technical analysis and their results were released in December 2014 and presented at the January 7, 2015 Working Group meeting.

In addition to Working Group meetings, staff has met frequently with the members of the Industry RECLAIM Coalition and other stakeholders throughout this rule-making to answer questions and discuss any concerns related to this proposed amendment. Also, staff has presented an update on the progress of this rule development to the Stationary Source Committee on March 21, 2014 and July 24, 2015. During the entire rulemaking process, staff has kept the public and stakeholders adequately informed on all upcoming milestones. Based on concerns that have been raised by the regulated community, the rulemaking schedule has been adjusted. At the earliest practical time staff will continue to apprise stakeholders of any future scheduling changes. To date there have not been any scheduling changes that would have given stakeholders less time to provide comments.

While it is true that the technical analysis for this rulemaking effort was not complete at the time the NOP/IS was released for public review and comment, the technical analysis for this proposed amendment is currently well-developed. The Draft PEA reflects the staff proposal for a 14 ton per day shave of NOx RTC holdings which is consistent with the project as described in the NOP/IS. In fact, the Draft PEA fully analyzes the potential environmental impacts that were identified in the NOP/IS as having potentially significant adverse effects.

The public hearing for these proposed rule amendments is currently scheduled for November. As the rule development process continues, there will be subsequent opportunities for the public and stakeholders to provide comments on staff's technical analysis, such as the 45-day public review and comment period provided for this Draft PEA.

6-5 This comment expresses the desire for commentators to continue to work with the SCAQMD on this rulemaking. SCAQMD staff appreciates the input of all stakeholders and looks forward to future discussions regarding the proposed changes to the NOx RECLAIM program.

Comment Letter #7

PARAMOUNT PETROLEUM

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January 30, 2015

Ms. Barbara Radlein
Mr. Joseph Cassmassi
South Coast Air Quality Management District
21865 E. Copley Dr.
Diamond Bar, CA 91765

Re: Comments on Proposed RECLAIM Regulation XX Amendment and associated CEQA Notice of Preparation and Initial Study (NOP/IS)

Dear Ms. Radlein and Mr. Cassmassi:

Paramount Petroleum Corporation (Paramount) appreciates the opportunity to comment on the District's proposed amendments to Regulation XX, and the associated CEQA document. In particular, Paramount's comments will focus on the Project Description contained in the CEQA document and the clear inconsistency between the Project Description and how the proposed rule changes will impact Paramount's refinery. These comments are being addressed to both the District's CEQA section and the Rule Development Division. We would like to begin our comments by stating that we were gratified that the District undertook efforts to visit the various refineries in the District and look at the cost effectiveness of various controls strategies. 7-1

The current Nitrogen Oxide (NOx) RECLAIM universe consists of approximately 276 facilities. The objective of the Proposed Project is to achieve additional NOx emission reductions on the top 39 RECLAIM facilities. However, the reduction allocation distribution currently being analyzed in the CEQA document is a single cut across the board of fifty percent shave to all RECLAIM facilities as a worse-case scenario. Paramount believes that there is clear discrepancy between the project's objectives and the scenario that is being analyzed. Thus we believe that the Project Description is flawed and the District cannot undertake a proper CEQA analysis. To demonstrate how the proposed project would adversely impact affected facilities, Paramount will use itself as an example. 7-2

The CEQA Project Description provided in the CEQA document identifies six refineries owned by five companies (Tesoro, Phillips 66, Chevron, Exxon/Mobile, and Ultramar (Valero)) that operate FCCUs (fluid catalytic cracking units), boilers and heaters, gas turbines, and SRU/TGU (sulfur recovery unit/tail gas unit), and proposes selective catalytic reduction (SCR) as BARCT for these process units and concludes that the proposed reduction is achievable and cost effective. Paramount does not dispute the 7-3

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District's analysis with respect to these facilities. But conspicuously absent from the Project Description's analysis is any mention of the Paramount Refinery. 7-3 Concluded

The top 39 facilities primarily consist of refineries and power plants. Paramount is twenty- ninth on this "top emitters" with aforementioned refineries taking the top seven spots. The average refinery NOx emissions excluding Paramount during the 2011 to 2013 time period was approximately 1.1 million pounds. Paramount's emissions averaged about 80,000 pounds or approximately 7 percent of the other refineries' average emissions. There is a clear size difference between Paramount and other refiners. 7-4

The District's proposed shave, which is based upon a BARCT of SCR, fails to take into account the equipment differences between complex fuel producing refineries and less complex refineries like Paramount. More importantly it fails to take into account that since the last shave in 2005, Paramount has accounted for third of SCR's installed and one-half of the sources controlled by SCR's at refineries. 7-5

If the rules proposed reductions were cost effective Paramount would not be preparing these comments. The District's own staff concluded that there is only one source at Paramount that meets the BARCT cost effectiveness criteria and the independent consultant hired by the District to review the cost effectiveness determinations concluded that none of the sources at Paramount meet the BARCT cost effectiveness criteria. 7-6

Paramount understands that there is a need to reduce NOx emissions within the Basin and therefore we are not asking to be excluded from the shave.[1] Instead we believe that the District needs to recognize, that not all refineries are the same and revises the Project Description and the rule to acknowledge that there is a distinct line between Paramount and other major refineries that justifies a separate shave percentage. 7-7

Paramount does not operate a FCCU or Coker, has a lower throughput and different product mix than most if not all of the other refineries in the Basin, and has installed more SCRs on its sources since 2005 than any other refineries. Therefore our opportunities to control sources are significantly more limited than the majors. The across the board fifty percent shave would impose a severe and unjustified burden on Paramount when compared to other refineries. 7-8

Moreover, Paramount is a Low Complexity-Low Energy refinery as defined in the proposed California Air Resources Board (CARB) Low Carbon Fuel Standard. The CARB Low Complexity-Low Energy means that Paramount is more fuel efficient in its processing operations on a per barrel bases than larger more complex refiners. It also means that Paramount is a lower NOx emitter on a per barrel bases than other refineries in the Basin. Attached to this letter is a bubble chart showing the 2013 Green House Gas 7-9

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[1] Paramount is opposed to making any RECLAIM credits non-tradable and believes that doing so is contrary to the spirit and purpose of the RECLAIM Program.

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(GHG) emissions for the various refineries in the Basin. GHG emissions are a surrogate for fuel combustion. The Chart clearly demonstrates that there is a distinct line between us and the other refineries. Looking at average refinery NOx emissions of the subject refineries (excluding Paramount), the average mass of NOx emitted on a per barrel bases was 6.52 pounds per barrel of name plate capacity during the 2011 to 2013 time period. Paramount emitted approximately 3 pounds of NOx per barrel of name plate capacity using the highest annual NOx emissions from the past 10 years. Even if other refiners reduced their NOx emissions by fifty percent on a per barrel bases, their emissions would still be more than of Paramount. 7-9 Concluded

Since the necessitated AQMP emission reductions do not require that the District imposes a fifty percent shave across the board, Paramount believes that the District should use this flexibility to allow for subsets of facilities within the universe of facilities to be shaved and apply a different shave percentage to these facilities. In the case of the refining sector, refineries that do not have Cokers and FCCUs and/or meet the CARB definition of a Low Complexity-Low Energy refinery could be considered a separate subset of the refining sector subject to a lower shave percentage. Paramount would be happy to work with the District to craft appropriate language to define this subset. 7-10

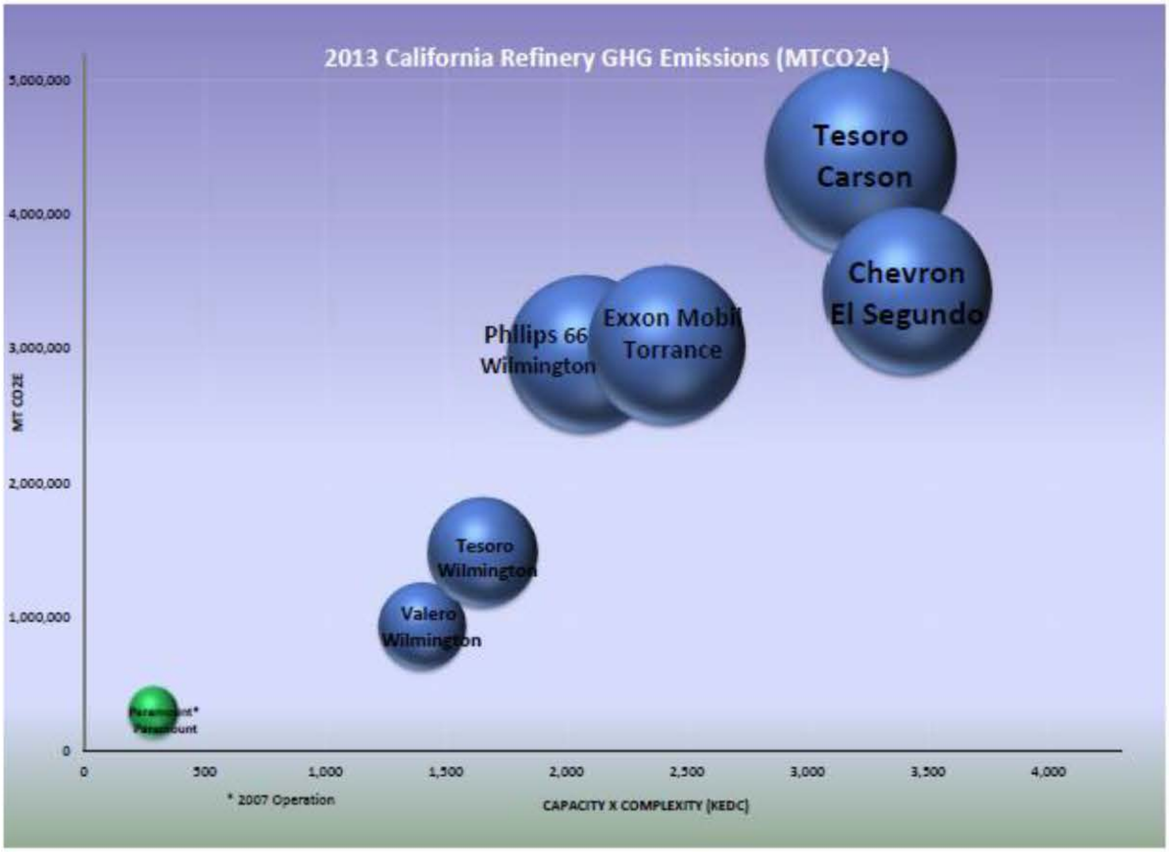
Please feel free to contact me with any questions you may have.

Sincerely,

Matthew Jalali

Matthew Jalali
Managing Director of Environmental Affairs

CC:
Gary Quinn, AQMD



2013 California Refinery GHG Emissions (MTCO2e)
Tesoro Carson
Chevron El Segundo
Phillips 66 Wilmington
Exxon Mobil Torrance
Tesoro Wilmington
Valero Wilmington
Paramount* Paramount
MT CO2E
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
* 2007 Operation
CAPACITY X COMPLEXITY (KEDC)

RESPONSES TO COMMENT LETTER #7
(Paramount Petroleum - January 30, 2015)

7-1 This introductory comment explains that this comment letter has been submitted in response to the proposed amendments to Regulation XX and the associated CEQA document and focuses on an alleged an inconsistency between the project description and project implementation. This comment also expresses appreciation for efforts made by SCAQMD staff to visit various refineries and to examine the cost effectiveness of various control strategies. Thus, responses to the specific concerns are presented in Responses 7-2 through 7-10.

7-2 This comment explains that there is a discrepancy between the objective of the proposed project (e.g., to achieve NOx emission reductions from the top 39 RECLAIM facilities out of a total of 276) versus the worst-case analysis in the CEQA document (e.g., a 50 percent shave across all 276 facilities). This comment asserts that the project description in the CEQA analysis is flawed and because of this flaw, a proper CEQA analysis cannot be done.

Since the release of the NOP/IS, the proposed project has been modified to apply a shave to the holders of the top 90 percent of RTCs. However, based on feasibility and cost-effectiveness, NOx controls would be installed at only 20 facilities. The remainder would surrender RTCs or purchase RTCs in order to comply with the proposed project. The environmental impacts would only be associated with the installation and operation of NOx control equipment.

7-3 This comment agrees that SCR is BARCT for FCCUs, boilers and heaters, gas turbines, and SRU/TGUs that are operated by six refineries owned by five companies and that the proposed reductions are achievable and cost-effective. This comment also points out that project description in the CEQA document does not mention the commentator's facility (e.g., Paramount Petroleum).

SCAQMD staff is pleased that you agree with its BARCT analysis related to the larger refiners. The proposed project was designed to apply BARCT to various types of equipment and processes operated by a multitude of industries, including but not limited to refineries. The equipment/processes for which BARCT was identified are as follows: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns, and, 11) metal heat treating furnaces. While Paramount Petroleum is considered a refinery that is part of the NOx RECLAIM program, Paramount Petroleum does not operate a FCCU or SRU/TGU. Paramount Petroleum operates refinery boilers and heaters that were analyzed for BARCT, but these units were found to be already at BARCT. For the proposed RTC shave calculation, Paramount has been included as part of the non-major refinery category that would be subject to a lesser shave than the major refineries. See Table 8 in PAR 2002.

7-4 This comment identifies Paramount Petroleum as being a relatively small emitter in the NOx RECLAIM program by being ranked 29th out of the top 39 emitters when compared to the other refiners that take the top seven spots.

SCAQMD staff agrees that there is a difference in NOx emissions between Paramount Petroleum and the other larger refiners operating in the District. However, because the Basin is designated as an "extreme" nonattainment area for the 8-hour ozone standard under federal law, and because NOx is a precursor to ozone formation, NOx emission reductions are being sought from a large variety of RECLAIM sources as part of this rulemaking as well as from non-RECLAIM facilities that emit considerably less emissions than Paramount (as part of other rulemaking activities in accordance with control measures in the Final 2012 AQMP).

7-5 This comment claims that the proposed shave does not take into account the equipment differences between complex fuel producing refineries and less complex refineries like Paramount Petroleum. This comment also claims that the proposed shave does not take into account that one-third of the SCRs that were installed in response to the 2005 NOx RECLAIM shave were installed at Paramount Petroleum.

The task of achieving RECLAIM NOx emission reductions has historically been approached in a programmatic manner. The size of a particular facility or the number of sources within a facility with potential emission reduction opportunities has not always been a determining factor as to whether a particular facility would be subject to a shave. As explained in Response 7-3, Paramount Petroleum operates refinery boilers and heaters that were analyzed for BARCT, but these units were found to be already at BARCT. For the proposed RTC shave calculation, Paramount has been included as part of the non-major refinery category that would be subject to a smaller shave than the major refineries.

7-6 This comment expresses disagreement with SCAQMD's position that the proposed BARCT that would only apply to one source at Paramount Petroleum is cost-effective. This comment claims that the consultant hired by the SCAQMD did not identify any sources at this facility that meets the BARCT cost-effectiveness criteria.

As explained in Response 7-3, Paramount Petroleum operates refinery boilers and heaters that were analyzed for BARCT, but these units were found to be already at BARCT. The proposed shave would affect those facilities that are among the top 90% of NOx RTC holders. For the proposed RTC shave calculation, Paramount has been included as part of the non-major refinery category that would be subject to a smaller shave than the major refineries at 47 percent. There is an opportunity within the current proposed rule that would exempt a facility from the requirements of the shave if the facility can demonstrate that their equipment is at BARCT, in addition to other criteria. The requirements to qualify for this exemption are outlined in Proposed Amended Rule 2002 (i).

7-7 This comment is requesting the SCAQMD to revise the project description to include a separate shave percentage for Paramount Petroleum.

Staff has not established an individual shave for Paramount Petroleum but this facility is included in the non-major refinery category and the NOx RTCs for this category would be subject to a 47 percent shave.

7-8 This comment claims that the opportunities to further control NOx emissions at the Paramount Petroleum facility are significantly limited and an across the board 50 percent shave would impose a "severe and unjustified" burden on this facility.

SCAQMD staff agrees that this facility is different than the major refineries based on the equipment they operate. The proposed project would apply a NOx RTC shave of 67 percent to the major refineries, while for non-major refining facilities, a NOx RTC shave of 47 percent would be applied.

SCAQMD staff is aware of Paramount Petroleum's concern about severe or unjustified burdens and have attempted to minimize the impact to this facility by applying a sector-based shave approach that excludes Paramount Petroleum from the major refineries category. In addition, there is a safety valve in the rule that may alleviate the burden of the shave to a facility's RTC allocation in the event of a shortage of RTCs in the market. If there is a shortage of credits which would result in an increase in the RTC price, the safety valve in the rule would provide access to non-usable, non-tradable credits in the event that the 12-month rolling average market price for discrete year credits rises above $15,000 per ton. Furthermore, as stated Response 7-6, a facility whose equipment is already at BARCT may apply to be exempted from the shave requirements if it meets the criteria in Rule 2002 (i).

7-9 This comment claims that Paramount Petroleum qualifies as a "Low Complexity-Low Energy" refinery as defined in CARB's Low Carbon Fuel Standard because of high fuel efficiency operations, lower NOx emissions per barrel and lower GHG emissions when compared to the other, larger refineries.

The commentator's assessment of NOx emissions on a per barrel bases appears to be correct. The proposed rule would reduce RTCs from this facility using a smaller percentage than applied to the other, larger refineries.

7-10 This comment claims that NOx emission reductions required by the AQMP do not require a 50 percent shave across the board and instead flexibility should be allowed to account for facility differences.

The staff proposal is the result of a much more rigorous and in-depth analysis as compared to the analysis that supported control measure CMB-01. For a market-based incentive program, SCAQMD staff is required by the California Health and Safety Code to conduct periodic BARCT assessments and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT assessment. CMB-01 anticipated this BARCT assessment but could not predict the results of the assessment, and therefore made commitments for a more modest reduction. This staff proposal recommends a reasonably available 14 tpd of NOx RTC reductions, based on

BARCT, as required by state law, and which are needed to help the Basin achieve the PM2.5 standards by 2019 and 2025 and the ozone standards by 2024 and 2032.

Also, as explained in Responses 7-6 and 7-8, this refinery will be excluded from the major refinery category and will be subject to a smaller shave percentage because of the differences in equipment operated.

Comment Letter #8

COMMENTS OF HARVEY EDER FOR SELF & PSPC PUBLIC SOLAR POWER COALITION ON THE RECLAIM NOX PROGRAM PAR CEQA DRAFT EA BIG TODAY JANUARY 30, 2015.

PUBLIC SOLAR POWER COALITION
1223 WILSHIRE BLVD. #647
SANTA MONICA, CA. 90403
harveyederpspc@yahoo.com
(310) 393 2589

ATT KEVIN ORELLANA

SEE ATTACHMENT A AN OVERVIEW OF THE KRAMER JUNCTION SEGS RECENT PERFORMANCE

1. SOLAR ENERGY IS BARCT AND SHOULD HAVE BEEN SUBMITTED AS THE BEST AVAILABLE RETROFIT TECHNOLOGY — OK. GO ON WITH THE BACK UP OPTIONS CITED BY STAFF BUT SOLAR THERMAL SYSTEMS WITH LINE FOCUS CONCENTRATOR WITHIN 100 MILES OF THE DISTRICT SUPPLYING 354 MW (MEGAWATTS) HAVE BEEN OPERATING FOR 30 TO 20 YEARS - SEE POWER POINT PRINT OUT 9 PAGES ON SEGS SOLAR ENERGY ELECTRIC GENERATING SYSTEMS (9 IN ALL — 1x 14MW 6x30 MW AND 2 80MW) THESE HAVE BEEN THE LONGEST OPERATING SOLAR THERMAL AT MODERATE TEMPERATURE 500—700 °F & HIGHER TEMPS CAN BE OPERATED FOR USE WITH POINT DOUBLE AXIS SOLAR CONCENTRATORS OF 1000 °F + + PLUS STORAGE (9 SEE THE 9 PAGE POWER POINT PRINT OUT PROVIDED BY PSPC/HE 8-1

2. PSPC/HE SHOULD BE HIRED AS CONSULTANT TO SHOW THE SOLAR OPTIONS BOTH SOLAR THERMAL & P.V. PHOTOVOLTAICS & HYBRIDS AS SOON AS POSSIBLE THIS CAN FORM THE CENTER OF ON, NEAR & FURTHER SOLAR THERMAL SCHP COMBINED SOLAR COMBINED HEATING & COOLING - DISTRICT HEATING + COOLING SYSTEM (ABSORPTION VIS LIC DR. BROWN ETC. AS WELL AS ELECTRICITY - THE REPAIR OF SEWAGE AND WATER SYSTEMS WILL BE PLANNED AT THE SAME TIME AS WELL AS REPLACING OLD NAT GAS SYSTEM ALA SAN BRUNO EXPLOSION IN PG&E TERRITORY GET 8-2

PAGE 1 OF 3

"2. BACT IS A TECHNOLOGY FORCING CONTROL MEASURE CITE 2012 CALIFORNIA SUPREME COURT DECISION ON VOC IN AMERICAN COATINGS ASSN VS SCAQMD. THE LAW IS CLEAR AND AS POINTED OUT IN THE CURRENT LITIGATION THAT THE COMMENTER HAS WITH THE DISTRICT (WITH A DRAFT AMENDED FOR CARB + NOW FEDERAL EPA ETC. YOU CAN PAY NOW FOR THE CONSTRUCTION AT A LOWER COSTS OR PAY MORE LATER. RECENT STUDY BY THE PRESIDENTS ECONOMIC ADVISORS SAYS + DEMONSTRATED THAT CLIMATE CHANGE IMPLEMENTATION WILL COST 40% + EVERY 10 YEARS THAT WE WAIT. 8-2 Concluded

3. THE SEGS PLANTS WERE BROUGHT TO THE SCD DECADES BY THE PLAINTIFFS/CONSULTANTS, THIS INFORMATION WAS PURGED BETWEEN EARLY 1991 AQMP DRAFT & THE FINAL ADOPTED IN MID YR JULY 1991 - OUR LITIGATION FOLLOWS BUT WITHOUT A FOLLOW THROUGH - THE TIME TO ACT IS NOW IF NOT YESTERDAY 8-3

4. A FULL CEQA EIR MUST BE DONE 8-4

5. IN REFERENCE TO THE DEC 5, 2014 DOCUMENT AT LEAST SOLAR ENERGY MUST BE STUDIED AS AN ALTERNATIVE THE AREAS COVERED ARE ENERGY, GHG GREEN HOUSE GASES, TRANSPORTATION & TRAFFIC AS WELL AS WATER (GIVEN THE FACT THAT OVER 20% OF THE DISTRICTS/STATES ENERGY IS USED TO MAKE WATER 8-5

PAGE 2 OF 3

6. Immediate total Solar Conversion means now or yesterday. Climate change etc was addressed in the 1992 BC cases that are in the Record in the Superior & Appellate Courts in the State as well as the Federal 9th Circuit Appeal Court. This time with a plethora of Environmental & Community Groups joining us HE/PSPC in Litigation. The drought continues 8-6

7. The fact that almost 24 years ago the District had all of the information in hand during litigation with us from the Sunshot initial draft mentioned by reference herein as well as the complete sections of Solar Thermal & Solar Photovoltaic Technology. Sunshot is a play on words for Kennedy's Moon Shot in the 1960's. Our 60% on it was to all Grid Parity 0.5 cents last year with only 40% of that passing. This is for everywhere in the U.S.A. All other the Record in SC 119641 Eder vs Schwarzenegger as well as R25627 as well as the Federal Record & Federal Register Sep. 3, 2014 and all information submitted to date as well as in the future are incorporated herein into the Record. 8-7

8. At the January 7 GB meeting Eder/PSPC stated that (as is part of the Record) no consultant was hired to study Solar Energy as an aspect which was been before the District & CARB for decades! 8-8

9. As the cover article in this week's Economist says Cheap Dawn of Sieze the Day. Gov. Brown set 50% Solar Renewables by 2030 of. Fine but he's off by 100% in technology and 100%/50% off in the Bygone to 2025! Solar Conversion Now! 8-9

Public Solar Power Coalition

Harvey Eder/Director

1223 Wilshire Blvd. #607
Santa Monica Ca. 90403
Since 1978

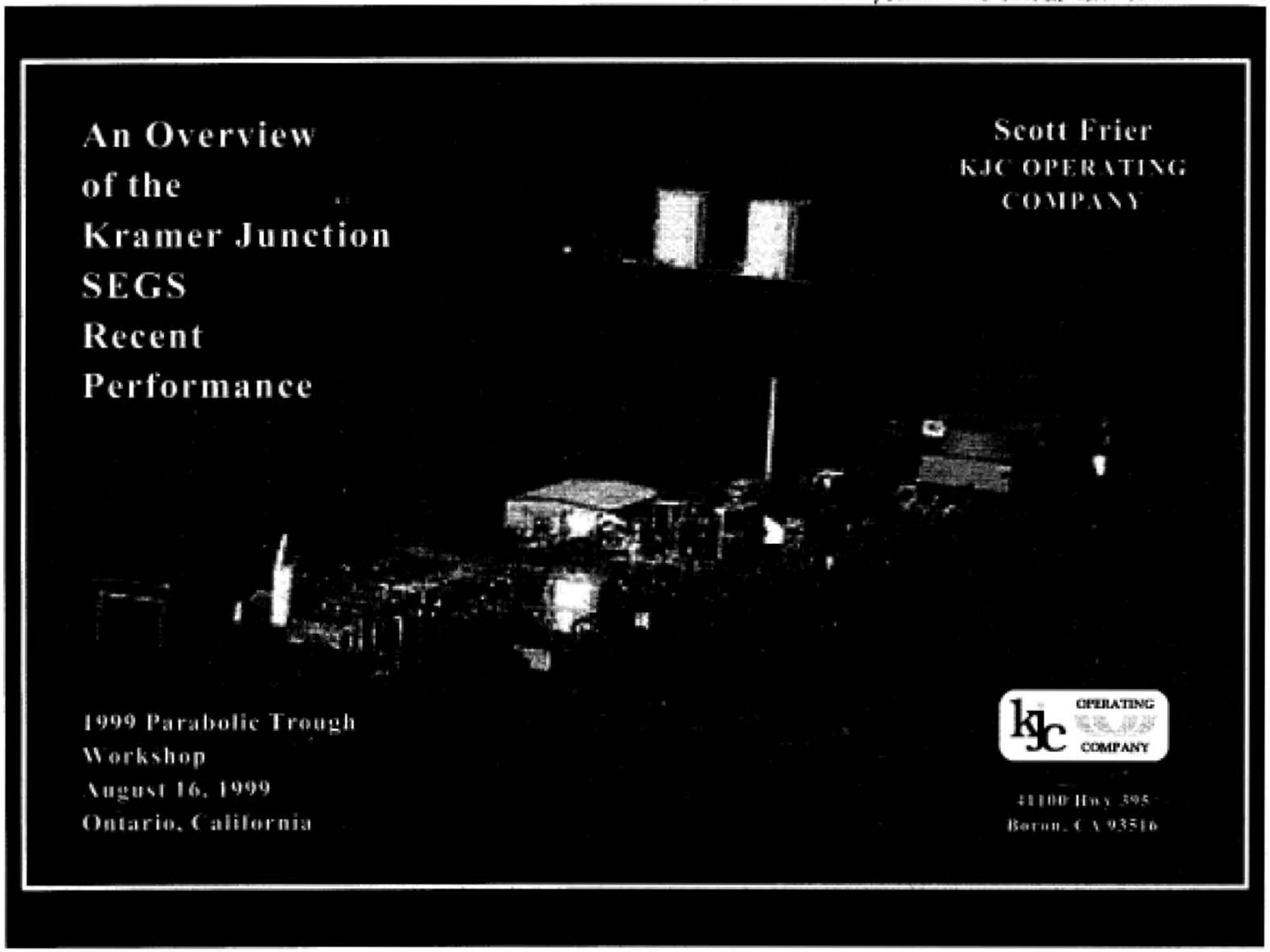
harveyederpspc@yahoo.com
(310) 393-2589
Solar Conversion Now!

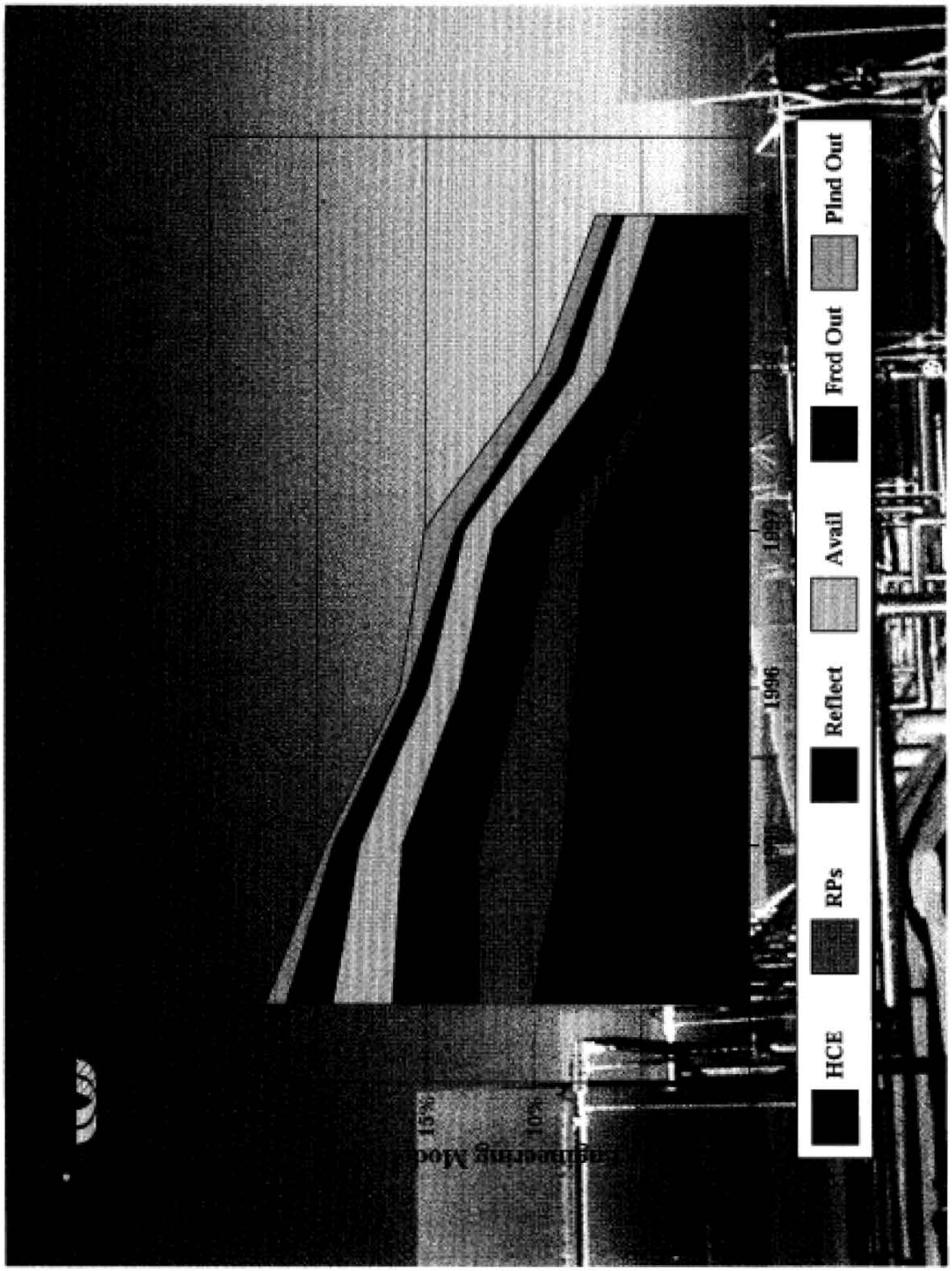
The Sun Makes the Wind Blow, Water Flow & Plants Grow.
It can be used directly or stored for days, weeks or months.

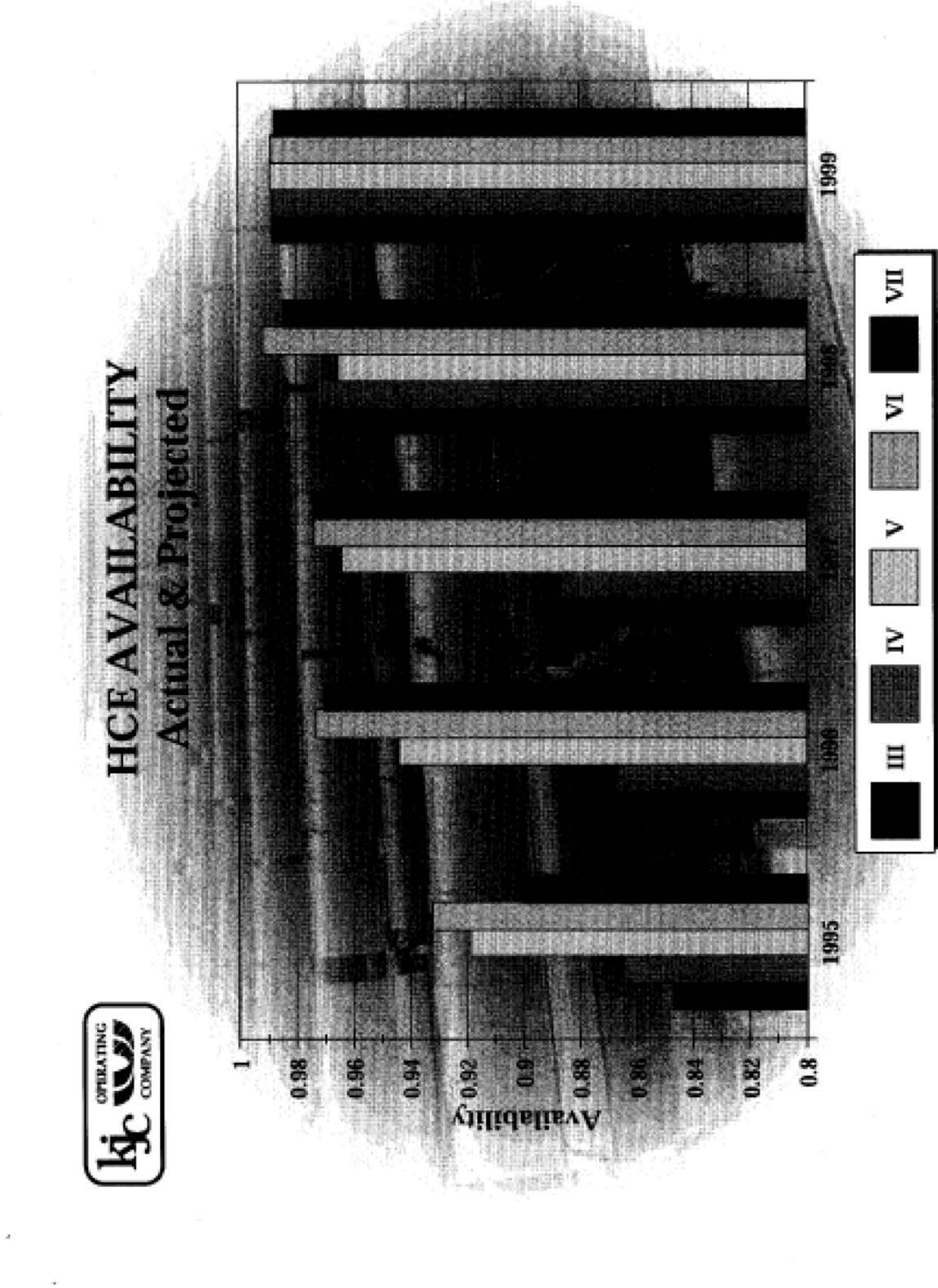
PS- As weeks take Acid is Formed in LA County Seeded by Heindel

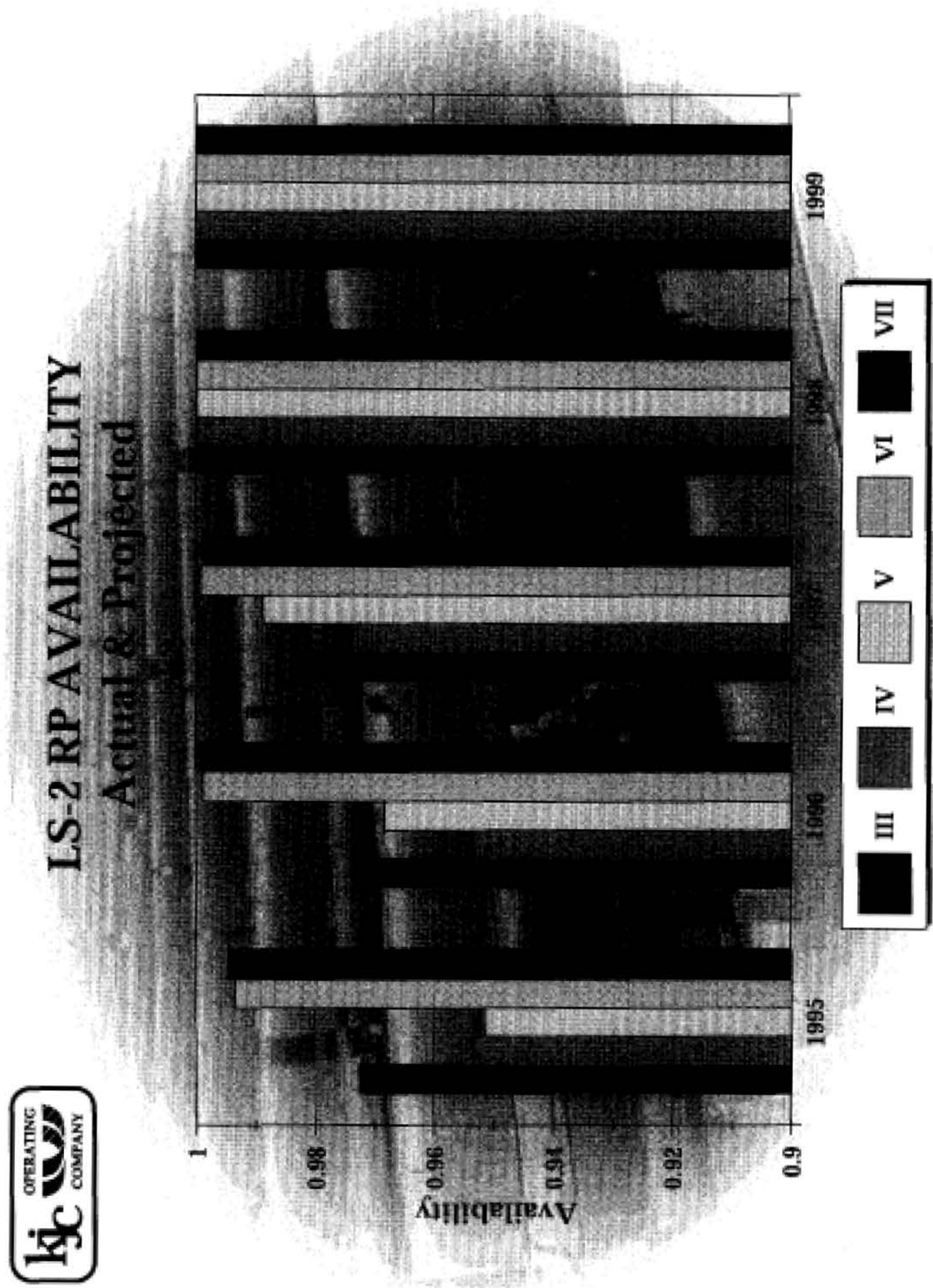
Page 3 of 3
+ Attachment A

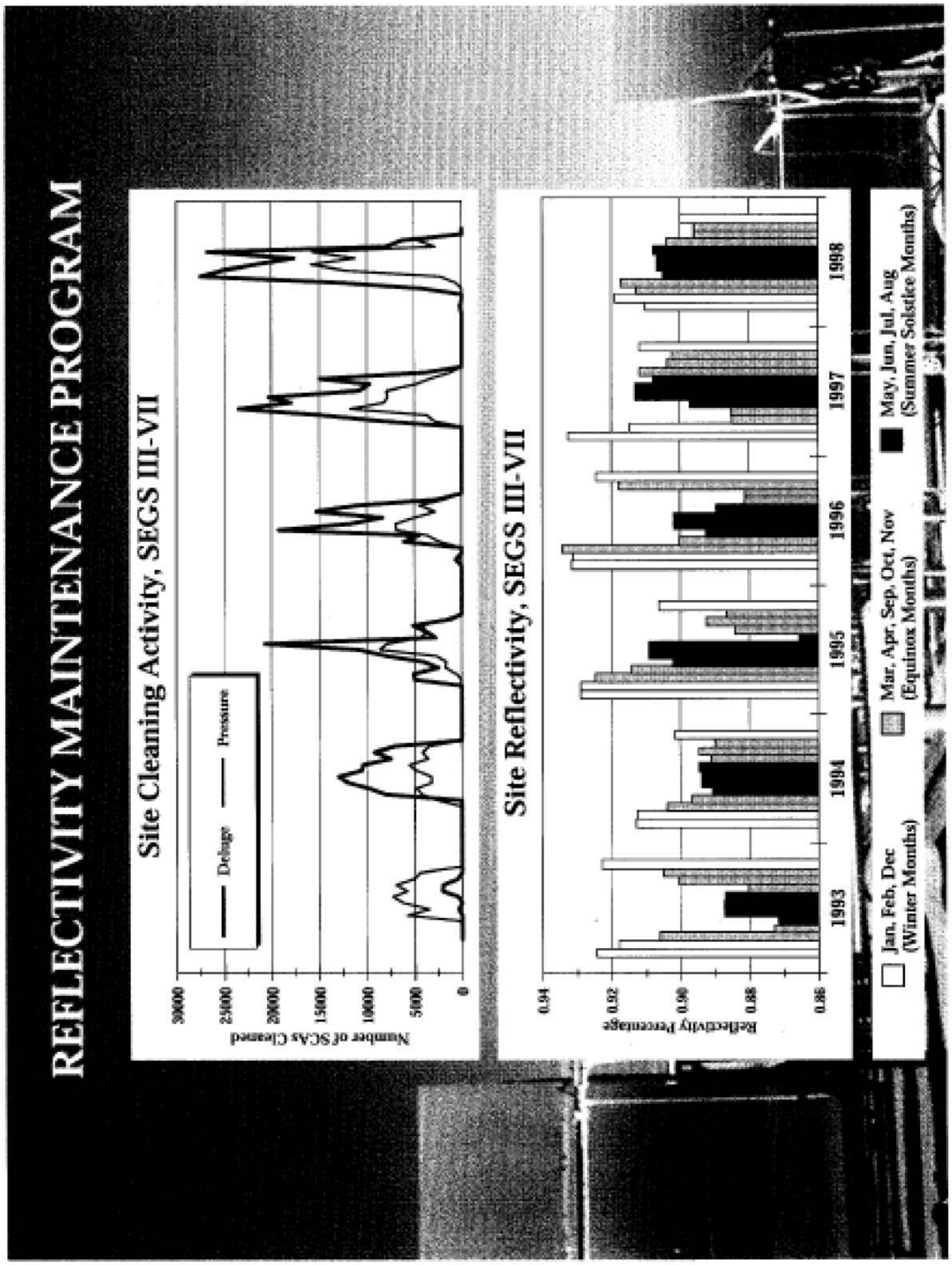
1/30/15 ATTACHMENT A WITH 3 PAGES OF COMMENTS OF HARVEY EDER FOR SEPC & PSPC PUBLIC SOLAR POWER COALITION

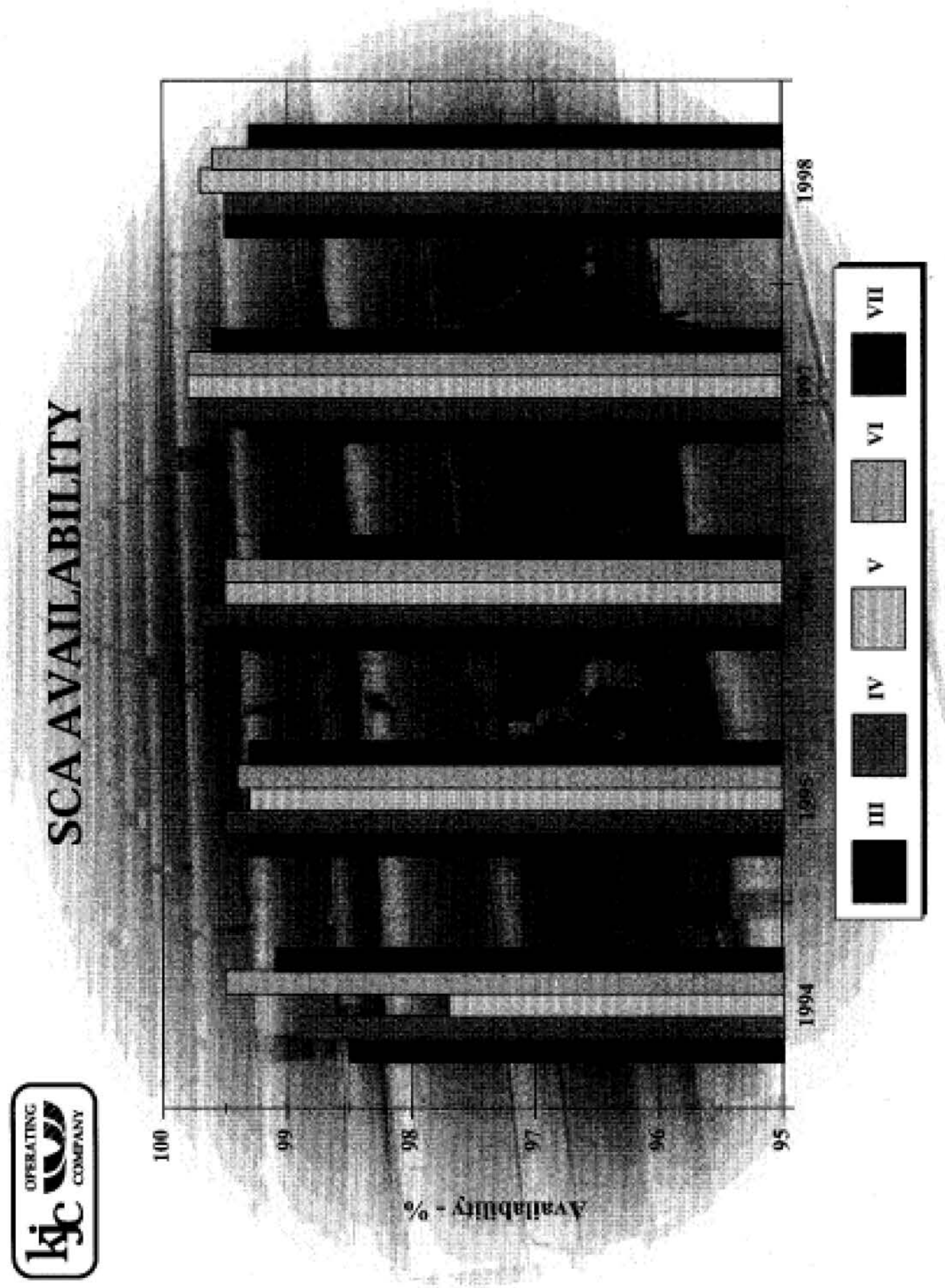



15%
10%
1996
1997
HCE
RPs
Reflect
Avail
Frcd Out
Plnd Out


HCE AVAILABILITY
Actual & Projected
Availability
1
0.98
0.96
0.94
0.92
0.9
0.88
0.86
0.84
0.82
0.8
1995
1996
1999
III
IV
V
VI
VII


LS-2 RP AVAILABILITY
Actual & Projected
Availability
1
0.98
0.96
0.94
0.92
0.9
1995
1996
1999
III
IV
V
VI
VII
OPERATING
COMPANY


REFLECTIVITY MAINTENANCE PROGRAM
Site Cleaning Activity, SEGS III-VII
Deluge
Pressure
Number of SCAs Cleaned
30000
25000
20000
15000
10000
5000
0
Site Reflectivity, SEGS III-VII
Reflectivity Percentage
0.94
0.92
0.90
0.88
0.86
1993
1994
1995
1996
1997
1998
Jan, Feb, Dec (Winter Months)
Mar, Apr, Sep, Oct, Nov (Equinox Months)
May, Jun, Jul, Aug (Summer Solstice Months)


SCA AVAILABILITY
Availability - %
100
99
98
97
96
95
1994
1995
1998
III
IV
V
VI
VII

GROSS SOLAR PRODUCTION (MWh)

Year	SEGS III	SEGS IV	SEGS V	SEGS VI	SEGS VII	III - VII
1987	42,773	44,480	0	0	0	87,253
1988	60,724	63,856	62,827	0	0	187,407
1989	63,097	70,552	65,281	48,045	38,868	285,843
1990	70,510	75,801	72,449	62,682	57,661	339,103
1991	60,132	64,307	59,009	64,155	58,259	305,862
1992	48,702	50,971	55,383	47,097	46,940	249,093
1993	58,248	58,935	67,685	55,725	54,110	294,703
1994	56,892	57,795	66,255	56,934	53,281	291,157
1995	56,663	54,929	63,757	63,650	61,210	300,209
1996	64,170	61,970	71,439	71,409	70,138	339,127
1997	64,677	64,503	75,936	70,019	69,186	344,321
1998	70,598	71,635	75,229	67,358	67,651	352,471

July YTD Gross Solar Electric Production (MWh)

Year	SEGS III	SEGS IV	SEGS V	SEGS VI	SEGS VII	III .. VII
1987	28,869	30,060	0	0	0	58,930
1988	40,929	41,414	41,553	0	0	123,896
1989	41,846	45,920	42,494	29,055	23,044	182,359
1990	45,251	47,321	45,137	38,156	35,160	211,025
1991	40,775	43,096	37,189	43,194	38,953	203,207
1992	30,886	31,704	34,536	28,944	29,177	155,247
1993	37,933	37,337	43,028	34,573	33,673	186,544
1994	37,706	38,283	43,369	37,616	34,678	191,653
1995	36,484	35,059	41,489	38,010	36,092	187,734
1996	42,082	41,063	46,246	46,664	46,073	222,128
1997	41,705	41,133	50,028	45,280	45,733	223,879
1998	45,468	45,588	48,555	42,460	43,508	225,580
1999	43,361	44,652	42,064	44,580	41,427	216,091

KRAMER JUNCTION HISTORIC INSOLATION, 1989-1999

Kramer Junction Average Daily DNR Data (kWh/m2/day)

	Table 1	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Avg
Jan	5.183	6.519	5.852	4.754	4.740	3.401	5.852	3.027	6.401	4.861	5.011	5.655	5.098
Feb	6.019	6.145	5.879	6.613	4.290	4.241	5.111	6.851	4.849	7.092	4.613	6.365	5.641
Mar	6.735	7.325	6.984	6.630	3.870	6.539	7.410	6.170	7.316	8.554	7.500	6.930	6.839
Apr	8.385	8.707	7.535	8.896	6.670	8.149	7.546	8.144	9.103	8.393	8.416	7.330	8.081
May	9.290	9.190	9.368	9.596	6.927	8.463	8.612	7.674	9.649	9.242	8.562	9.318	8.782
Jun	9.849	10.360	10.312	10.166	8.675	9.554	10.820	10.044	10.620	9.929	10.662	10.498	10.149
Jul	9.423	9.906	9.624	9.194	8.549	10.239	9.288	10.402	9.335	9.845	10.663	9.471	9.683
Aug	8.738	9.594	9.355	8.850	8.091	9.466	8.935	9.973	9.253	9.176	9.572		9.227
Sep	7.950	8.528	8.807	7.261	7.524	9.443	8.115	9.370	9.375	7.780	7.981		8.418
Oct	7.076	7.261	8.208	7.503	6.108	6.904	7.149	8.140	7.661	8.351	7.802		7.509
Nov	5.697	6.950	6.905	6.496	5.994	6.176	6.830	6.683	6.448	5.445	6.814		6.474
Dec	4.905	6.330	6.283	4.290	4.374	6.141	5.070	5.408	4.782	6.008	7.118		5.580
Avg	7.443	8.077	7.938	7.521	6.337	7.409	7.573	7.654	7.922	7.896	7.913		7.642

Kramer Junction Average Daily DNR Data - YTD (kWh/m^2/day)

		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Avg
Jan	5.183	6.519	5.852	4.754	4.740	3.401	5.852	3.027	6.401	4.861	5.011	5.655	5.098
Feb	5.580	6.342	5.865	5.636	4.468	3.800	5.500	4.842	5.587	5.920	4.822	5.992	5.283
Mar	5.978	6.680	6.250	5.979	4.275	4.743	6.158	5.299	6.187	6.827	5.745	6.315	5.824
Apr	6.580	7.187	6.571	6.708	4.877	5.595	6.505	6.010	6.918	7.219	6.412	6.569	6.392
May	7.136	7.598	7.146	7.301	5.302	6.184	6.938	6.352	7.482	7.634	6.854	7.133	6.886
Jun	7.586	8.056	7.670	7.776	5.863	6.742	7.581	6.964	8.004	8.014	7.485	7.691	7.429
Jul	7.854	8.326	7.956	7.983	6.259	7.253	7.831	7.467	8.203	8.282	7.950	7.951	7.762
Aug	7.967	8.488	8.135	8.094	6.496	7.536	7.972	7.786	8.340	8.396	8.157		7.952
Sep	7.965	8.493	8.208	8.002	6.612	7.745	7.987	7.960	8.457	8.328	8.137		8.007
Oct	7.874	8.367	8.208	7.951	6.564	7.660	7.902	7.979	8.380	8.331	8.103		7.959
Nov	7.679	8.240	8.091	7.821	6.516	7.526	7.806	7.862	8.210	8.072	7.987		7.829
Dec	7.443	8.077	7.938	7.521	6.337	7.409	7.573	7.654	7.922	7.896	7.913		7.642

1998 ANNUAL PRODUCTION SUMMARY

Insolation						
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gross Electrical Prod						
Gross Solar - MWh	70698	71635	75229	67358	67651	352471
Gross Boiler - MWh	32563	32856	36887	31663	33470	167539
Gross Total - MWh	**103261**	**104491**	**112116**	**99021**	**101121**	**520010**
Net Elec Sold - A Chan						
On-Pk - MWh	16279	16074	16716	17143	16907	83119
Mid-Pk - MWh	58551	58897	63221	52574	54218	287462
Off-Pk - MWh	19166	19276	20410	17757	17639	94252
Super Off - MWh	0	0	0	0	0	0
Total - MWh	**93996**	**94250**	**100347**	**87474**	**88764**	**464832**
Net Purch - B Chan						
On-Pk - MWh	0	2	1	0	2	6
Mid-Pk - MWh	342	318	283	476	458	1877
Off-Pk - MWh	1254	1220	1407	1533	1474	6888
Super Off-Pk - MWh	617	568	665	711	696	3258
Total - MWh	**2214**	**2108**	**2356**	**2720**	**2631**	**12028**
Station Load						
Station Internal - MWh	9265	10241	11769	11547	12357	55178
Station Ext (B Ch) - MWh	2214	2108	2356	2720	2631	12028
Station Total - MWh	**11478**	**12349**	**14125**	**14267**	**14987**	**67206**
Station Internal - % of Gross	9.00%	9.80%	10.50%	11.70%	12.20%	10.60%
SCE Capacity Factor						
On-Pk - %	104	103	107	109	108	106
Mid-Pk - %	66	66	71	67	62	67
Off-Pk - %	17	17	18	17	15	17
Natural Gas Use						
Boiler - KSCF	411104	422372	455258	339460	359356	397510
Heater - KSCF	20048	15476	23518	2118	1080	12447
Total - KSCF	**431152**	**437848**	**478770**	**341578**	**360436**	**409957**
FERC Calc (LHV)						
Solar Input - MMBtu	1186056	1203316	1317270	959047	[illegible]	[illegible]
Gas Used - MMBtu	394820	400581	438508	312739	[illegible]	[illegible]
Monthly FERC Ratio	**24.97**	**24.98**	**24.98**	**24.98**	**24.98**	**24.98**

Subcontractor Report

September 2000 • NREL/SR-550-27925

Survey of Thermal Storage for Parabolic Trough Power Plants

Period of Performance: September 13, 1999–June 12, 2000

Pilkington Solar International GmbH
Cologne, Germany

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401-3393

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NREL Technical Monitor: Mary Jane Hale

Prepared under Subcontract No. AAR-9-29442-05

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List of Acronyms

ETDE	Energy Technology Data Exchange
EU	European Union
h	hour
HTF	heat transfer fluid
IEA	International Energy Agency
ISCCS	integrated solar combined cycle systems
kWh	kilowatt-hours
kWh_e	kilowatt-hours electric
kWh_t	kilowatt-hour thermal
MUSD	million U.S. dollar
MWe	megawatts electric
MW	megawatt
MWh	megawatt-hour
MWh_t	megawatt-hours thermal
NREL	National Renewable Energy Laboratory
PCM	phase change material
PNL	Pacific Northwest Laboratory
PNNL	Pacific Northwest National Laboratory
PSA	Plataforma Solar Alméria
PV	photovoltaics
RTR	reversible thermochemical reaction
SEGS	solar electric generating system
SERI	Solar Energy Research Institute
TES	thermal energy storage
ZSW	Center for Solar Energy and Hydrogen Research, Stuttgart, Germany

1.0 Introduction

The electrical output of a solar thermal electric plant is inherently in a state of change, being dictated by both predictable and unpredictable variations—the influences of time and weather. In either event, utility system needs may require a fully functional storage system to mitigate the changes in solar radiation or to meet demand peaks.

A distinct advantage of solar thermal power plants compared with other renewable energies, such as photovoltaics (PV) and wind, is the possibility of using relatively cheap storage systems. That is, storing the thermal energy itself. Storing electricity is much more expensive.

A thermal energy storage (TES) option can collect energy in order to shift its delivery to a later time, or to smooth out the plant output during intermittently cloudy weather conditions. Hence, the operation of a solar thermal power plant can be extended beyond periods of no solar radiation without the need to burn fossil fuel. Times of mismatch between energy supply by the sun and energy demand can be reduced.

When used with Integrated Solar Combined Cycle Systems (ISCCS), energy storage could provide another important advantage. If the plant operates at baseload, it will operate at full load only when enough solar energy is available. At part load, the turbine efficiency can decrease considerably. If fossil energy is used to augment turbine load (through the use of duct firing, a heat transfer fluid [HTF] heater, or a backup boiler) when solar is not available, the plant converts that fossil fuel at a substantially lower efficiency than if it had been used directly in the combined cycle. Using thermal energy storage instead of a fossil burner can help to overcome this problem.

Economic thermal storage is a key technological issue for the future success of solar thermal technologies.

1.1 Scope of this Report

The purpose of this report is to identify and selectively review previous work done on the evaluation and use of thermal energy storage systems applied to parabolic trough power plants. Appropriate storage concepts and technical options are first discussed, followed by a review of previous work. This review is divided into two parts: work done before 1990 and work done after that date. This division was chosen because much of the work currently cited in this field was carried out and reported prior to 1990, and a key objective of the review was to highlight more recent results though they are less plentiful. Finally, observations and conclusions on the status of TES systems for trough plants are put forward, based on the body of literature covered.

1.2 Storage Concepts for Solar Thermal Systems

The principle options for using TES in a solar thermal system highly depend on the daily and yearly variation of radiation and on the electricity demand profile. As noted above, the main options are:

- Buffering
- Delivery period displacement

- Delivery period extension
- Yearly averaging

The goal of a buffer is to smooth out transients in the solar input caused by passing clouds, which can significantly affect operation of a solar electric generating system (SEGS) plant. The efficiency of electrical production will degrade with intermittent insolation, largely because the turbine-generator will frequently operate at partial load and in a transient mode. If regular and substantial cloudiness occurs over a short period, turbine steam conditions and/or flow can degrade enough to force turbine trips if there is no supplementary thermal source to "ride through" the disturbance. Buffer TES systems would typically require small storage capacities (maximum 1 hour full load).

Delivery period displacement requires the use of a larger storage capacity. The storage shifts some or all of the energy collected during periods with sunshine to a later period with higher electricity demand or tariffs (electricity tariffs can be a function of hour of the day, day of the week, and the season). This type of TES does not necessarily increase either the solar fraction or the required collection area. The typical size ranges from 3 to 6 hours of full load operation.

The size of a TES for delivery period extension will be of similar size (3 to 12 hours of full load). However, the purpose is to extend the period of power plant operation with solar energy. This TES increases the solar fraction and requires larger solar fields than a system without storage.

Yearly averaging of electricity production requires much larger TES and solar fields. In general, these are very expensive systems and have not been given serious consideration in the literature, nor will they be considered here.

Definitive selection of storage capacity is site- and system-dependent. Therefore, detailed statistical analysis of system electrical demand and weather patterns at a given site, along with a comprehensive economic tradeoff analysis, are desirable in a feasibility study to select the best storage capacity for a specific application.

1.3 Design Criteria

A key issue in the design of a thermal energy storage system is its thermal capacity - the amount of energy that it can store and provide. However selection of the appropriate system depends on many cost-benefit considerations.

The cost of a TES system mainly depends on the following items:

- The storage material itself
- The heat exchanger for charging and discharging the system
- The cost for the space and/or enclosure for the TES

From the technical point of view, the crucial requirements are:

- High energy density (per-unit mass or per-unit volume) in the storage material
- Good heat transfer between heat transfer fluid (HTF) and the storage medium

- Mechanical and chemical stability of storage material
- Compatibility between HTF, heat exchanger and/or storage medium
- Complete reversibility for a large number of charging/discharging cycles
- Thermal losses
- Ease of control

The most important design criteria are:

- Nominal temperature and specific enthalpy drop in load
- Maximum load
- Operational strategy
- Integration into the power plant

All these facts have to be considered when deciding on the type and the design of thermal storage. This review focuses on thermal energy storage for parabolic trough power plants, which operate under certain temperature limits. TES capacities up to 8 hours full load will be considered, which could significantly increase the solar share of a hybrid power plant, such as an ISCCS.

2.0 Technical Storage Options

Thermal energy storage can be classified by storage mechanism (sensible, latent, chemical) and by storage concept (active or passive).

2.1 Storage Media

Thermal storage can utilize sensible or latent heat mechanisms or heat coming from chemical reactions.

Sensible heat is the means of storing energy by increasing the temperature of a solid or liquid. Latent heat, on the other hand, is the means of storing energy via the heat of transition from a solid to liquid state. For example, molten salt has more energy per unit mass than solid salt.

Table 1 shows the characteristics of candidate solid and liquid sensible heat storage materials and potential phase change (latent) heat storage media for a SEGS plant.

For each material, the low and high temperature limits are given these limits, combined with the average mass density and heat capacity, lead to a volume-specific heat capacity in kWh_t per cubic meter. The table also presents the approximate costs of the storage media in dollars per kilogram, finally arriving at unit costs in $\$/kWh_t$.

The average thermal (heat) conductivity given in the table has a strong influence on the heat transfer design and heat transfer surface requirements of the storage system, particularly for solid media (high conductivity is preferable). High volumetric heat capacity is desirable because it leads to lower storage system size, reducing external piping and structural costs. Low unit costs obviously mean lower overall costs for a given thermal capacity.

2.1.1 Sensible Heat Storage

Thermal energy can be stored in the sensible heat (temperature change) of substances that experience a change in internal energy. The stored energy is calculated by the product of its mass, the average specific heat, and the temperature change. Besides the density and the specific heat of the storage material, other properties are important for sensible heat storage: operational temperatures, thermal conductivity and diffusivity, vapor pressure, compatibility among materials, stability, heat loss coefficient as a function of the surface areas to volume ratio, and cost.

Table 1. Candidate Storage Media for SEGS Plants (Geyer 1991)

Storage Medium	Temperature Cold (°C)	Temperature Hot (°C)	Average density (kg/m³)	Average heat conductivity (W/mK)	Average heat capacity (kJ/kgK)	Volume specific heat capacity (kWh$_t$/m³)	Media costs per kg ($/kg)	Media costs per kWh$_t$ ($/kWh$_t$)
Solid media								
Sand-rock-mineral oil	200	300	1,700	1.0	1.30	60	0.15	4.2
Reinforced concrete	200	400	2,200	1.5	0.85	100	0.05	1.0
NaCl (solid)	200	500	2,160	7.0	0.85	150	0.15	1.5
Cast iron	200	400	7,200	37.0	0.56	160	1.00	32.0
Cast steel	200	700	7,800	40.0	0.60	450	5.00	60.0
Silica fire bricks	200	700	1,820	1.5	1.00	150	1.00	7.0
Magnesia fire bricks	200	1,200	3,000	5.0	1.15	600	2.00	6.0
Liquid media								
Mineral oil	200	300	770	0.12	2.6	55	0.30	4.2
Synthetic oil	250	350	900	0.11	2.3	57	3.00	43.0
Silicone oil	300	400	900	0.10	2.1	52	5.00	80.0
Nitrite salts	250	450	1,825	0.57	1.5	152	1.00	12.0
Nitrate salts	265	565	1,870	0.52	1.6	250	0.70	5.2
Carbonate salts	450	850	2,100	2.0	1.8	430	2.40	11.0
Liquid sodium	270	530	850	71.0	1.3	80	2.00	21.0
Phase change media								
$NaNo_3$	308		2,257	0.5	200	125	0.20	3.6
KNO_3	333		2,110	0.5	267	156	0.30	4.1
KOH	380		2,044	0.5	150	85	1.00	24.0
Salt-ceramics ($NaCo_3$-$BaCO_3$/MgO)	500-850		2,600	5.0	420	300	2.00	17.0
NaCl	802		2,160	5.0	520	280	0.15	1.2
Na_2CO_3	854		2,533	2.0	276	194	0.20	2.6
K_2CO_3	897		2,290	2.0	236	150	0.60	9.1

4

2.1.1.1 Solid Media

For thermal storage, solid media usually are used in packed beds, requiring a fluid to exchange heat. When the fluid heat capacity is very low (e.g., when using air) the solid is the only storage material; but when the fluid is a liquid, its capacity is not negligible, and the system is called a dual storage system. Packed beds favor thermal stratification, which has advantages. Stored energy can easily be extracted from the warmer strata, and cold fluid can be taken from the colder strata and fed into the collector field.

An advantage of a dual system is the use of inexpensive solids such as rock, sand, or concrete for storage materials in conjunction with more expensive heat transfer fluids like thermal oil. However, pressure drop and, thus, parasitic energy consumption may be high in a dual system. This has to be considered in the storage design.

The cold-to-hot temperature limits of some solid media in Table 2 are greater than could be utilized in a SEGS plant because parabolic trough solar fields are limited to maximum outlet temperatures of about 400°C. Table 2 shows the effect on solid media by imposing this temperature limit on the storage medium temperature range, the unit heat capacities, and media costs.

Table 2. Solid Storage Media for SEGS Plants

Storage Medium	Heat Capacity kWh_t/m^3	Media Cost $\$/kWh_t$
Reinforced concrete	100	1
NaCl (solid)	100	2
Cast iron	160	32
Cast steel	180	150
Silica fire bricks	60	18
Magnesia fire bricks	120	30

Using these values and judging the options against the guidelines discussed above, the sand-rock-oil combination is eliminated because it is limited to 300°C. Reinforced concrete and salt have low cost and acceptable heat capacity but very low thermal conductivity. Silica and magnesia fire bricks, usually identified with high temperature thermal storage, offer no advantages over concrete and salt at these lower temperatures. Cast steel is too expensive, but cast iron offers a very high heat capacity and thermal conductivity at moderate cost.

2.1.1.2 Liquid Media

Liquid media maintain natural thermal stratification because of density differences between hot and cold fluid. To use this characteristic requires that the hot fluid be supplied to the upper part of a storage system during charging and the cold fluid be extracted from the bottom part during discharging, or using another mechanism to ensure that the fluid enters the storage at the appropriate level in accordance with its temperature (density) in order to avoid mixing. This can be done by some stratification devices (floating entry, mantle heat exchange, etc.).

The heat transfer fluid in a SEGS plant operates between the temperatures of 300°C and 400°C, approximately. Applying these limitations on temperature, and dropping mineral oil because it cannot operate at the upper temperature requirement gives the results shown in Table 3.

Table 3. Liquid Storage Media for SEGS Plants

Storage Medium	Heat Capacity kWh_t/m^3	Media Cost $\$/kWh_t$
Synthetic oil	57	43
Silicone oil	52	80
Nitrite salts	76	24
Nitrate salts	83	16
Carbonate salts	108	44
Liquid sodium	31	55

Both the oils and salts are feasible. The salts, however, generally have a higher melting point and parasitic heating is required to keep them liquid at night, during low insolation periods, or during plant shutdowns. Silicone oil is quite expensive, though it does have environmental benefits because it is a non-hazardous material, whereas synthetic oils may be classified as hazardous materials. Nitrites in salts present potential corrosion problems, though these are probably acceptable at the temperatures required here. (The U.S. Solar Two project has selected a eutectic of nitrate salts because of the corrosivity of nitrite salts at central receiver system temperature levels.)

2.1.2 Latent Heat Storage

Thermal energy can be stored nearly isothermally in some substances as the latent heat of phase change, that is, as heat of fusion (solid-liquid transition), heat of vaporization (liquid-vapor), or heat of solid-solid crystalline phase transformation. All substances with these characteristics are called phase change materials (PCMs). Because the latent heat of fusion between the liquid and solid states of materials is rather high compared to the sensible heat, storage systems utilizing PCMs can be reduced in size compared to single-phase sensible heating systems. However, heat transfer design and media selection are more difficult, and experience with low-temperature salts has shown that the performance of the materials can degrade after a moderate number of freeze-melt cycles. LUZ International Ltd. proposed evaluation of an innovative phase-change salt concept to the solar community that used a series of salts in a "cascade" design (to be discussed later).

Table 1 showed, for a number of potential salts, the temperature at which the phase change takes place as well as the heat capacity (heat of fusion). Data for the salts shown in that table that are applicable to SEGS plants are shown in Table 4 below. It can be seen that the heat capacities, at least for the nitrites, are high and unit costs are comparatively low.

Table 4. Latent Heat Storage Media for SEGS Plants

Storage Medium	Heat Capacity kWh_t/m^3	Media Cost $/kWh_t$
$NaNO_3$	125	4
KNO_3	156	4
KOH	85	24

2.1.3 Chemical Storage

A third storage mechanism is by means of chemical reactions. For this type of storage it is necessary that the chemical reactions involved are completely reversible. The heat produced by the solar receiver is used to excite an endothermic chemical reaction. If this reaction is completely reversible the heat can be recovered completely by the reversed reaction. Often catalysts are necessary to release the heat. This is even more advantageous as the reaction can then be controlled by the catalyst.

Commonly cited advantages of TES in a reversible thermochemical reaction (RTR) are high storage energy densities, indefinitely long storage duration at near ambient temperature, and heat-pumping capability. Drawbacks may include complexity, uncertainties in the thermodynamic properties of the reaction components and of the reaction's kinetics under the wide range of operating conditions, high cost, toxicity, and flammability.

Although RTRs have several advantages concerning their thermodynamic characteristics, development is at a very early stage. To date, no viable prototype plant has been built.

2.2 Storage Concepts

Storage concepts can be classified as active or passive systems. Active storage is mainly characterized by forced convection heat transfer into the storage material. The storage medium itself circulates through a heat exchanger. This heat exchanger can also be a solar receiver or a steam generator.

The main characteristic of a passive system is that a heat transfer medium passes through storage only for charging and discharging. The heat transfer medium itself does not circulate.

2.2.1 Active Thermal Energy Storage

Active thermal systems typically utilize tank storage. They can be designed as one tank or two tank systems.

Active storage is again subdivided into direct and indirect systems. In a direct system the heat transfer fluid, which collects the solar heat, serves also as the storage medium, while in an indirect system, a second medium is used for storing the heat.

Two prominent examples of two-tank systems for solar electric applications are the storage systems of the SEGS I (Kroizer 1984) and Solar Two plants (Kelly and Lessly 1994, Pacheco and Gilbert 1999, and Valenti 1995). Figure 1 shows a schematic flow diagram of SEGS I. An initial experience with a small-scale two-tank molten salt system has already been described (Chinen et al. 1983).

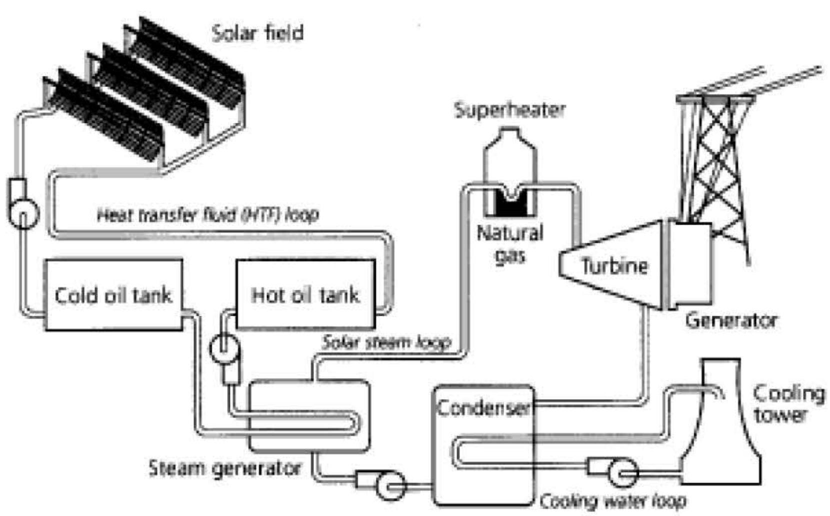

Figure 1. Schematic flow diagram of SEGS I plant

A two-tank system uses one tank for cold HTF coming from the steam generator and one tank for the hot HTF coming directly out of the solar receiver before it is fed to the steam generator. The advantage of this system is that cold and hot HTF are stored separately. The main disadvantage is the need for a second tank. In this type of system, the storage tanks are directly coupled to the HTF pressure levels (which is not necessarily a disadvantage).

The single-tank system reduces storage volume and cost by eliminating a second tank. However, in a single-tank system it is more difficult to separate the hot and cold HTF. Because of the density difference between hot and cold fluid, the HTF naturally stratifies in the tank, from coolest layers at the bottom to warmest layers at the top. These systems are called thermocline storage. Experience with thermocline storage was described by Castro et al. 1992, Dinter et al. 1990, Dugan 1980, and Kandari 1990. Maintaining the thermal stratification requires a controlled charging and discharging procedure, and appropriate methods or devices to avoid mixing. Filling the storage tank with a second solid storage material (rock, iron, sand etc.) can help to achieve the stratification.

2.2.2 Passive Thermal Energy Storage

Passive systems are generally dual medium storage systems. The HTF carries energy received from the energy source to the storage medium during charging and receives energy from the storage material when discharging. These systems are also called regenerators.

The storage medium can be a solid, liquid, or PCM. In general, a chemical storage system employs at least two media.

The main disadvantage of regenerators is that the HTF temperature decreases during discharging as the storage material cools down. Another problem is the internal heat transfer. Especially for solid materials, the heat transfer is rather low, and there is usually no direct contact between the HTF and the storage material as the heat is transferred via a heat exchanger.

3.0 State of the Art

3.1 Existing TES Systems in Solar Thermal Plants

Of eight installed thermal energy storage systems in solar thermal electric plants, seven have been of an experimental or prototype nature and one has been a commercial unit. Table 5 gives the characteristics of the existing units. All have been sensible heat storage systems: two single-tank oil thermocline systems, four single medium two-tank systems (one with oil and three with salt) and two dual medium single-tank systems. To put the size of these systems in perspective, a 30-MWe SEGS plant with a plant efficiency of 35% would require about 260 MWh_t for a 3-hour storage capability. This is considerably larger than any other solar thermal electric storage system built up to now.

All of these systems were successful to varying degrees, recognizing that most were development units that were expected to reveal design flaws or issues as a basis for future design improvements.

Two important characterizations of storage systems are the "round-trip efficiency" and the cost per unit of thermal energy delivery ($\$/kW_t$). The round-trip efficiency is, simply, the ratio of the useful energy recovered from the storage system to the amount of energy initially extracted from the heat source. This efficiency is affected by the laws of thermodynamics and by heat losses in the tanks, piping, and heat exchangers in the system; electric parasitic losses needed to circulate storage system fluids constitute additional losses.

Efficiency and cost experience from existing systems are informative but of limited relevancy to commercial plants because most of the existing facilities were one-of-a-kind development projects. Nevertheless, round-trip efficiencies of more than 90% were measured in many of the systems listed in Table 5, though some systems were as low as 70%. Both the oil systems and molten salt systems were shown to be technically feasible. While various problems arose due to mistakes in design, construction or operation, no fundamental issues surfaced for these approaches.

The SEGS I storage system cost $\$25/kW_t$ in 1984 dollars, with the oil representing 42% of the investment cost. The oil used in the later SEGS plants for operation up to 400°C costs approximately eight times more than the SEGS I oil. This was reason enough that a storage system similar to the SEGS I storage concept was not repeated in later SEGS plants. However, there were other important considerations, such as total system investment, very large tank size requirements, and inflexibility compared to a back-up system.

Table 5. Existing TES Systems

Project	Type	Storage Medium	Cooling Loop	Nominal Temperature Cold (°C)	Hot (°C)	Storage Concept	Tank Volume (m³)	Thermal Capacity (MWh)
Irrigation pump Coolidge, AZ, USA	Parabolic Trough	Oil	Oil	200	228	1 Tank Thermocline	114	3
IEA-SSPS Almeria, Spain	Parabolic Trough	Oil	Oil	225	295	1 Tank Thermocline	200	5
SEGS I Daggett, CA, USA	Parabolic Trough	Oil	Oil	240	307	Cold-Tank Hot-Tank	4160 4540	120
IEA-SSPS Almeria, Spain	Parabolic Trough	Oil Cast Iron	Oil	225	295	1 Dual Medium Tank	100	4
Solar One Barstow, CA, USA	Central Receiver	Oil/Sand/ Rock	Steam	224	304	1 Dual Medium Tank	3460	182
CESA-1 Almeria, Spain	Central Receiver	Liquid Salt	Steam	220	340	Cold-Tank Hot-Tank	200 200	12
THEMIS Targasonne, France	Central Receiver	Liquid Salt	Liquid Salt	250	450	Cold-Tank Hot-Tank	310 310	40
Solar Two Barstow, CA, USA	Central Receiver	Liquid Salt	Liquid Salt	275	565	Cold-Tank Hot-Tank	875 875	110

3.2 Summary of Work Performed Before 1990

This section reviews the most relevant investigations and evaluations carried out prior to about 1990. Selected literature from this period has been listed in the References, but only selected works are explicitly discussed here. A valuable overview of the applicability of thermal storage to solar power plants was provided by Geyer 1991. Table 6 shows the storage systems initially considered there, though of these only a few were investigated in detail. The final systems are listed in the following paragraphs.

Dual medium sensible heat systems

Two single-tank alternatives were analyzed, one in which HTF oil flows through a storage medium of concrete and another in which the storage medium is solid salt. Cast iron and cast steel were eliminated as storage media due to high cost, even though they offered thermodynamic advantages.

Table 6. Candidate Storage Concepts for SEGS Plants

TES Concepts	Storage Type	Status*	Assessment
Sensible Active	Two-Tank Oil	T	Basic concept, state-of-the-art
	HITEC	T	2 variants analyzed based on existing PSA/THEMIS designs
	Thermocline	T	Proved on pilot scale, no advantages over basic two tank system
Sensible DMS	Oil/Cast Iron	T	Proved on pilot scale, no advantages over basic two tank system
	Oil/Steel	LR	Used in chipboard presses
	Oil/Concrete	MR	Several variants analyzed
	Oil/Solid Salt	MR	Several variants analyzed
PCM	Oil/PC Salts	HR	Several cascade arrangements analyzed
Chemical	Oil/Metal Hybrids	HR	Early state of development, no lead concepts, no cost data

* Nomenclature: **T**: Tested / **LR**: Low Risk / **MR**: Medium Risk / **HR**: High Risk

Sensible heat molten salt system

A two-tank system (similar to SEGS I) utilizing the HITEC salt was chosen. HITEC is a eutectic mixture of 40% $NaNO_2$, 7% $NaNO_3$ and 53% KNO_3 with a 142°C melt-freeze point.

Phase-change systems

These higher-risk systems were judged to have high uncertainty in technical feasibility and cost, but were evaluated for their potential in this application. Three different phase-change concepts were evaluated. The first was a LUZ design using five PCMs in a series, or cascade, design (SERI 1989); the second was a design by the Spanish company INITEC, which also used five PCMs but in a different heat exchanger configuration; the third design originated with the German companies Siempelkamp and Gertec (SGR) and used three commercially available PCMs along with concrete for the higher temperatures.

3.2.1 Overview of Results

Storage system designs for the SEGS conditions based on these five concepts were developed in Dinter et al. 1990. Summary results are presented here giving overall system volume, thermal storage capacity and utilization, and specific costs in $/kWh$_t$ of capacity.

The utilization measure is an interesting aspect of storage systems. Earlier discussion described some of the aspects of temperature differences within the HTF fluid and between the HTF and a solid storage medium. Another aspect of storage design is the temperature difference within the medium itself. In a two-tank liquid system, for example, the entire fluid is heated to a charged temperature and hence the entire storage medium is utilized. PCM systems theoretically also have very high utilization factors. In a solid system, however, temperature gradients required for thermal conduction through the media itself prevent full utilization of the material. In this case, 100% utilization would be achieved if the entire solid medium were heated to the full charging temperature. Hence, the "potential" storage capacity might be two or three times higher than the practical storage capacity. Detailed heat transfer calculations on specific designs provide this type of information.

Figure 2 gives results on the total volume, storage capacity and utilization, and specific cost of the six candidate systems analyzed for SEGS plants. For comparison purposes, we will select the INITEC PCM design as representative of the PCM class, with the qualifier that there is much more uncertainty and technical risk in the PCM results than in the sensible heat oil-solid systems or in the sensible heat HITEC molten salt system.

With regard to volume, the concrete and salt media fill about 6,900 and 5,200 m^3 of space, respectively, whereas the molten salt and PCM system need 2,600 m^3. If the cross-sectional area perpendicular to the flow measured 13m by 13m, the length of the concrete system would be 41 m compared to a 15-m length for the PCM system. A major reason for the larger sizes of the concrete and solid salt systems is the poor volume utilization. The concrete system, for example, is utilized at 36% of its full potential capacity. The molten salt and PCM systems, on the other hand, have utilization factors up to 100%. The concrete system does, however, have cost advantages due to the very low cost of concrete, which results in a low system cost even though there is more structure required for this larger volume system.

Generally, the storage costs developed in this assessment vary from \$25–\$50/kWh_t (on the order of \$65–\$130/kWh_e). At the low end, TES units of 270 and 450 MWh_t capacity would have a capital cost of 6.8 MUSD and 11.3 MUSD, respectively.

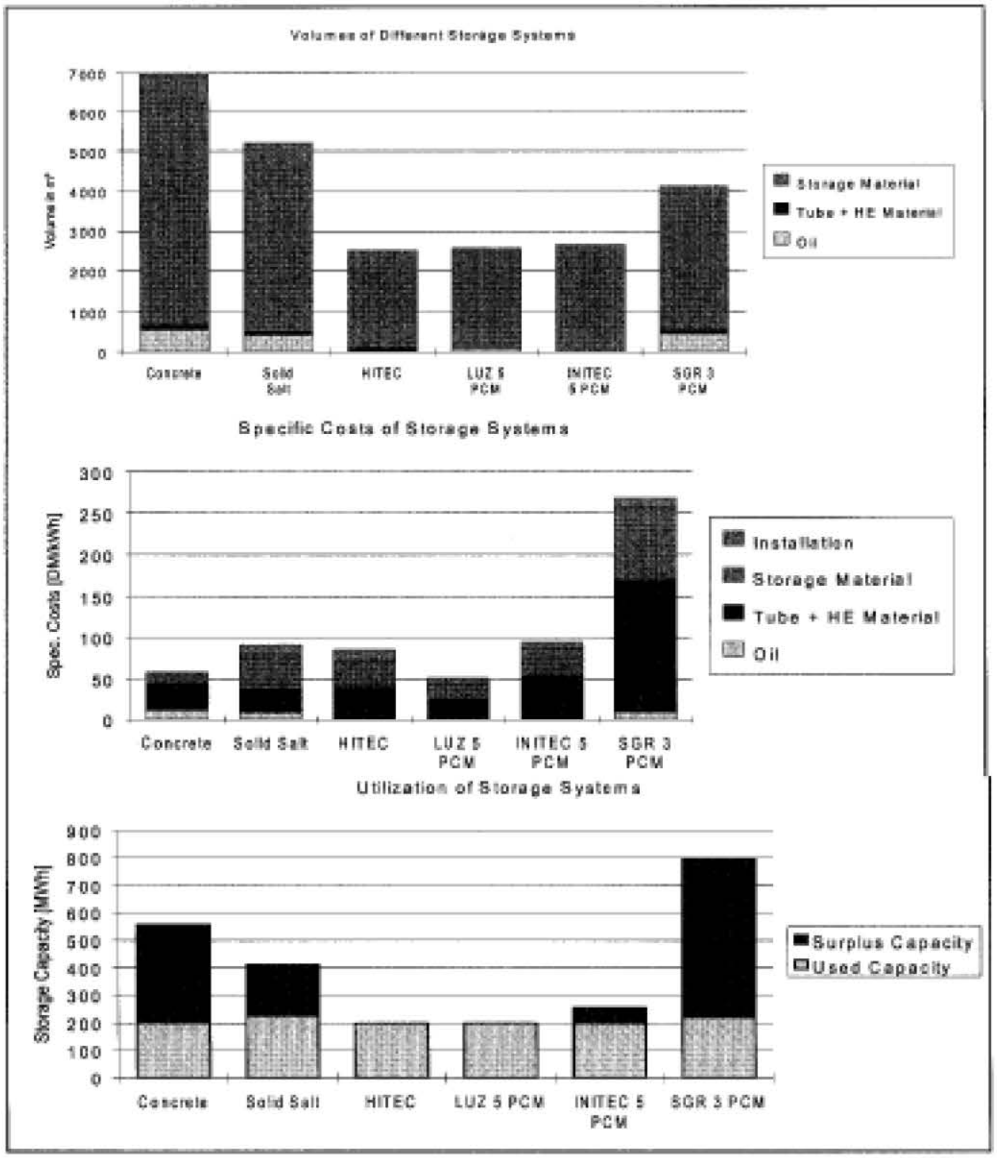

Figure 2. Results of TES evaluations for reference SEGS plant (Dinter et al. 1990)

3.2.2 SEGS TES Workshop

A symposium workshop (SERI 1989) on TES systems for SEGS plants, held in 1989 and sponsored by the Solar Energy Research Institute (SERI—now the National Renewable Energy Laboratory—NREL), discussed several of the options presented above. While the workshop focused on phase-change material concepts, both sensible heat storage and chemical storage were also included in the agenda. The more detailed evaluations reported in Dinter et al. 1990 were completed subsequent to the workshop.

With respect to sensible heat storage, the workshop concluded that this approach could result in a cost-effective system. While no new research would be required, thorough and careful engineering development and small-scale testing would be necessary. Issues such as thermal expansion, potential leakage, heat transfer configuration, and heat exchange optimization require more detailed design within the context of a design concept.

Latent heat (or phase-change) storage was considered to be in a more primitive state of development. While the concept is promising, considerable research, system development, and proof-of-concept testing would be required. Concerns on heat transfer characteristics and heat exchange configuration were expressed. Of several possible configurations, it was concluded that both shell-and-tube heat exchangers and a system of encapsulated particles of phase-change salts were worthy of exploration, with the latter approach having both more potential for cost-effectiveness and a lower probability of success.

3.3 Experience and Research on TES since 1990

To analyze the work that has been done since 1990 on thermal storage for troughs, a thorough literature review was carried out. This review included a computerized literature search in the Energy Technology Data Exchange (ETDE) Energy database.

The ETDE Energy Database contains more than 3.8 million bibliographic records with abstracts for energy research and technology information from around the world. The EDTE, a multilateral information exchange program, was established in 1987 under the auspices of the International Energy Agency (IEA). Member countries share their energy research and technology information through the Energy Database. The database covers journal articles, research reports, conference papers, books, dissertations, computer software, and other miscellaneous types. Of all the records, 7.1% are devoted to energy storage and conservation.

Appendix A gives the report of the database search including the keywords used to identify the records of interest.

Sixty-five references that met the criteria defined through the keywords were identified. After evaluating the 65 abstracts, a lesser number (21) were applicable to TES systems in parabolic trough technology, and this group was added to the reference list given in Chapter 5. The abstracts for this group are included in Appendix B.

Table 7, summarizing the literature analysis, lists all identified works that may help in the selection of a candidate storage concept. The main results for the most promising options are discussed below.

Table 7. Results from Literature Review (after 1999)

Author	Year	Storage Concept	Type of Work*	Temperature Range	Capacity
M. Mitzel et al.	1990	Hydrid/Magnesium Thermochemical Storage	TH	?	-
Brown et al.	1991	Oxide/Hydroxide chemical storage	TH	300°C–400°C	-
D.Steiner, M. Groll	1995	MgH2/Mg Chemical Storage	EX-LS	280°C–480°C	14 kWh
K. Lovegrove A. Luzzi et al.	1999	Ammonia Based Thermochemical Storage	EX-LS	450°C–650°C	?
B.Beine, F. Dinter, R. Ratzesberger et al.	1992	Concrete	EX-LS	290°C–400°C	50 kWh
J. Pacheco, D.B. Kelly et al.	1999	Molten-Salt 2-Tank	EX-FS	290°C–566°C	114 MWh
H. Michels, E. Hahne	1996	Cascaded PCM	EX-LS	250°C–450°C	8.5 kWh

* TH theoretical work
EX-LS experimental work in lab scale
EX-FS experimental work in full scale

In addition to the experimental works listed in Table 7, more theoretical works on TES were performed by Brower 1992, Lund 1994, Meier and Winkler 1993, Steel and Wen 1981, and Steinfeld et al. 1991.

3.3.1 Overview of Progress

3.3.1.1 Experience at Solar Two

The most significant recent work on molten salt storage comes from the experience in the Solar Two Project. This prototype facility, decommissioned in 1999, was a 10-MW power tower system using a nitrate eutectic molten salt as the HTF. A schematic of the system is shown in Figure 3. Molten salt is pumped from the cold storage tank through the tower receiver and then to the hot storage tank. When dictated by the operation, the hot salt is pumped through the steam generation system and then back to the cold tank. Solar Two is capable of producing 10 MWe net electricity. A number of lessons on the equipment design, material selection, and operation of molten salt systems were learned during the 1-1/2 years of testing and evaluation.

Solar Two used an efficient, molten nitrate-salt thermal-storage system (Pacheco and Gilbert 1999). It consisted of an 11.6-m-diameter by 7.8-m-high cold-salt storage tank, a 4.3-m-diameter by 3.4-m-high cold-salt receiver sump, an 11.6-m-diameter by 8.4-m-high hot-salt storage tank, and a 4.3-m-diameter by 2.4-m-high hot-salt steam generator sump. The design thermal storage capacity of the Solar Two molten salt system was 105 MWh_t—enough to run the turbine at full output for 3 hours. The measured gross conversion efficiency of the 12-MWe (10-MWe-net) Solar Two turbine was 33%. Actual thermal storage capacity based on the mass of salt in the tanks, accounting for (subtracting) the 3-foot heels in each tank, and with design temperatures—1050°F hot salt, 550°F cold salt—was 114 MWh_t.

The system contained 1.5 million kilograms of nitrate salt composed of a mixture of 60% $NaNO_3$ and 40% KNO_3, provided by Chilean Nitrate Corporation (New York). This salt melted at 220°C and was thermally stable to about 600°C.

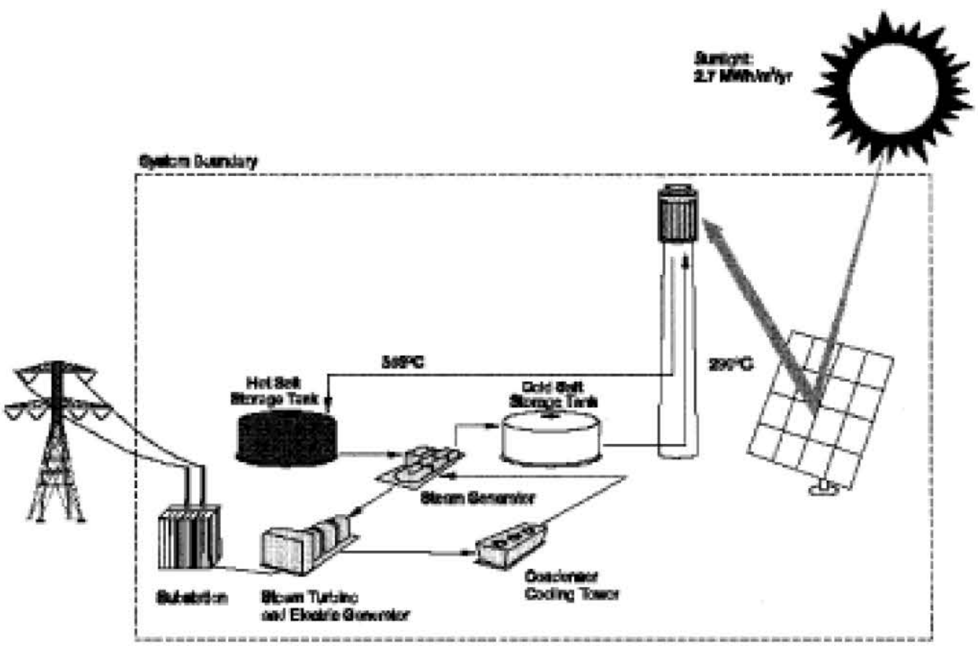

Figure 3. Molten salt power tower system schematic

<u>Heat Losses</u>

Several tests were conducted to quantify the thermal losses of major pieces of equipment throughout the plant and to compare the values to calculated estimates. The major pieces of equipment evaluated were the hot tank, cold tank, steam generator sump, and receiver sump. There were two methods of measuring the thermal losses in the tanks and sumps. One method was to turn off all auxiliary heaters and track the rate of decay of the average tank or sump temperature. By knowing the salt level, and thus the volume of salt in the vessel, an estimate of the heat loss could be made. Another method was to have the heaters energized and regulate the inventory at a set temperature. Once the vessel was at steady state, the power consumption of the heaters was measured over a long period of time. The electrical power consumption was assumed to be equal to the heat loss rate.

A summary of the measured and calculated thermal losses is shown in Table 8. The thermal losses for the tanks and sumps were equal to the calculated values within experimental error, except for the steam generator sump heat loss rate. The losses for the steam generator sump were higher than predicted, possibly because the insulation may have degraded significantly since it was installed. Salt had leaked out of the sump through flanges and into the insulation, which adversely affected its insulating properties. Based on the measured heat loss rates, the total energy lost to the environment over the course of a typical operating year corresponds to a 98% annual thermal efficiency.

Table 8. Measured and Actual Thermal Losses of Major Equipment

Major Equipment	Calculated Thermal Loss, kW	Measured Thermal Loss, kW
Hot Tank	98	102
Cold Tank	45	44
Steam Generator Sump	14	29
Receiver Sump	13	9.5

Operating Experience[1]

The capacity of the system is a function of the hot and cold salt temperatures. Hot salt temperatures at the bottom of the downcomer were typically only 1025°F because some of the isolation ball valves between the riser and downcomer leaked, attemperating the salt coming out of the receiver (which typically exited at 1050°F). The lower salt temperature derated the capacity of the thermal storage system by 5% to 108 MWht.

The fractional amount of the energy sent to thermal storage that was later discharged to the steam generator to make electricity is nearly 1, but is a function of the availability. The thermal losses are basically a fixed loss to the environment. When the plant availability is high, the collected energy increases and the losses are a smaller fraction of the total energy sent to storage. For example, on Dec. 2, 1997, on a sunny winter day, the receiver collected 217 MWh, which was sent to the steam generator system to make electricity. Based on a constant thermal loss of 185 kW from the hot and cold tanks, and the receiver and steam generator sumps, the total energy lost to the environment that day was 185kW x 24 h = 4.43 MWh or 2.0% of the collected energy. In contrast, on a sunny summer day—June 18, 1998—the receiver collected 334 MWht

[1] Comments provided by James Pacheco, Sandia National Laboratories Albuquerque, December 15, 1999.

and the thermal losses were 1.3% of the collected energy. Even with the very prototypical nature of Solar Two (i.e., poor availability, frequent outages, first year operation, etc.), over several months the fractional amount lost to the environment was only 6% of collected energy. If the plant ran with higher availability, i.e., typical mature operation, the factional amount of stored energy lost to the environment would only be about 2% of collected energy.

There were no major operational problems with the thermal storage system and, in general terms, the system ran satisfactorily. Typically, the plant started using the stored energy within an hour or two after the receiver began collecting energy. Scenarios were also run, however, to demonstrate dispatching energy several times or to demonstrate the production of a constant output of electricity at night and through clouds. A number of practical lessons were learned, and no barriers to future implementation were evident.

3.3.1.2 Concrete

Limited prototype testing has been done on the concrete-steel thermal storage concept. Between 1991 and 1994, two concrete storage modules were tested at the storage test facility at the Center for Solar Energy and Hydrogen Research (ZSW) in Stuttgart, Germany (Ratzesberger et al. 1994). Figure 4 shows the prototype concrete module installed in the center's laboratory.

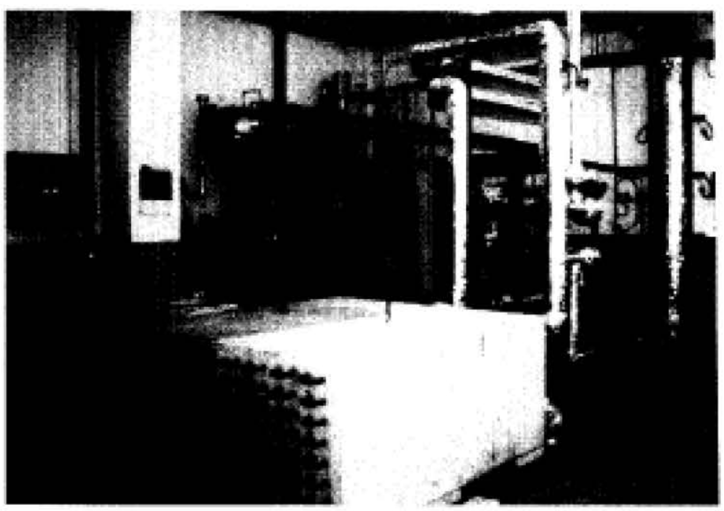

Figure 4. Test Facility for TES with two concrete storage modules at ZSW

The test results gained at ZSW in principle confirm the performance predictions given by Baddruddin, Dinter et al. 1992. Based on these tests, a numerical calculation model for concrete storage was developed by Ratzesberger 1995. He also proposed a slightly different design that results in the same performance but with considerably lower pressure loss in the storage module. According to his results, the pressure loss in a

200-MWh module can be reduced from 4.3 to 1.9 bar. The integration of a sensible heat storage system like concrete storage into a SEGS plant is depicted in Figure 5.

Ratzesberger recalculated the cost for storage and obtained a price of $40/kWh in 1994 U.S. dollars. This is slightly higher than the number given by Dinter. As a next step in the development of concrete storage, a project has recently been proposed to the EU (European Union) by a European team (CONTEST 1999). The proposed project consists of a prototype module with a capacity of 1–2 MWh to be erected at the PSA and connected to a parabolic trough solar field. The project, if funded, will be led by the German company Siempelkamp Giesserei GmbH & CO KG. In the company's proposal, it is projected that storage costs of $26/MWh in commercial scale can be realized.

Summarizing the work performed on concrete storage up to now, it can be concluded that this concept presents a relatively cheap option of thermal storage. The feasibility has already been proven in laboratory tests. The highest uncertainty still remains in the long-term stability of the concrete material itself after thousands of charging cycles. Special tests in a climatic chamber dedicated to investigation of this potential problem are included in the aforementioned EU proposal.

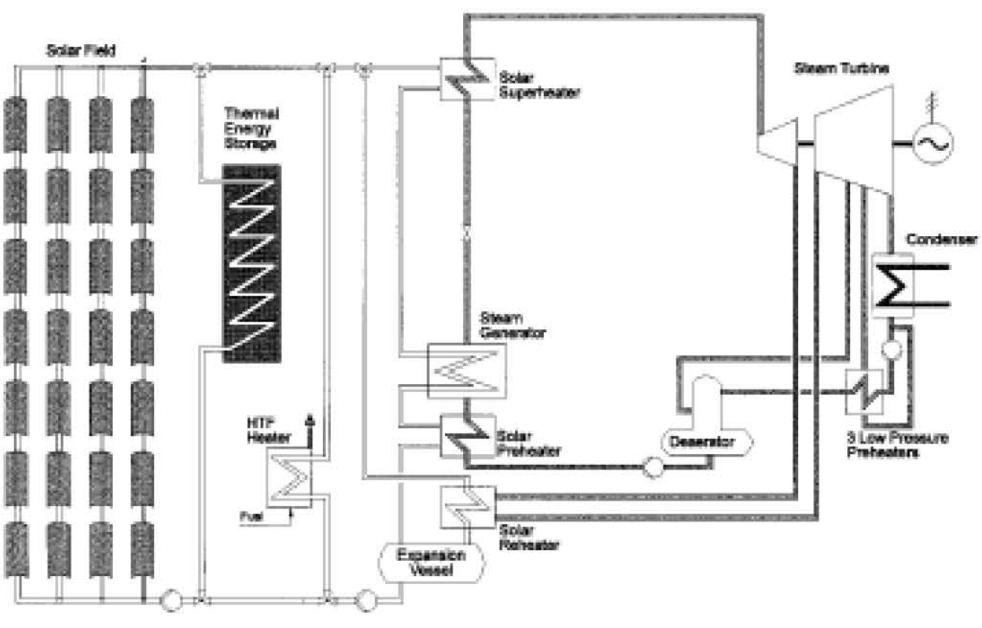

Figure 5. Schematic diagram of a SEGS plant with TES

3.3.1.3 Phase Change Material

Following the recommendations of the SERI workshop held in 1988 (SERI 1989), the ZSW, Germany, started to investigate storage using PCM. It was found by Dinter et al.

1990 that PCM storage has a relatively high heat capacity per volume and offers the lowest cost of all concepts investigated in this study (see also Figure 2).

A storage test facility has been set up in ZSW's laboratory allowing the investigation of various storage concepts independent from the sun. Electrical heating is the heat source, and a cooling tower is the heat sink. Figure 6 shows the flow diagram of the test loop with three PCM modules connected to the system. The modules can be charged by the HTF flow separately or connected to each other in series or in parallel.

A major objective was to investigate the heat transfer mechanism of different PCM salts during phase change and of liquid salts (Hunold et al. 1994, 1992, 1992, and 1994). In the work of Hunold, only one storage module filled with one salt was investigated in each case. Hunold showed that phase change storage is technically feasible and proposed a storage design built out of a shell and tube heat exchanger in a vertical orientation. By adjusting the vertical orientation of the tubes, natural convection and heat transfer can be improved. He selected the nitrate $NaNO_3$, with a melting point at 305°C, as appropriate storage material for the SEGS-type power plants.

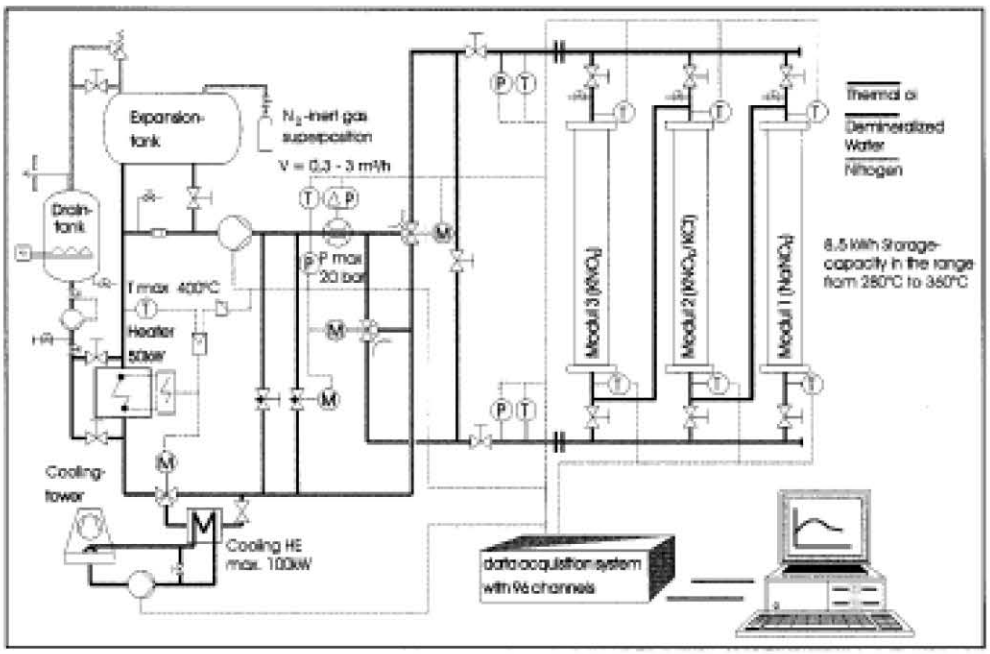

Figure 6. Flow diagram of storage test loop at ZSW (Michels and Hahne 1996)

However, one can only take full advantage of PCM storage by connecting several modules with different salts and different melting points in series as shown in Figure 7. Michels 1996 explained, by means of Figure 8, the reason for this. The left diagram shows the HTF temperature at the end of charging and discharging and the melting temperature of a single-stage salt storage as investigated by Hunold. During discharging the HTF temperature in the biggest part of the storage module is higher than the melting temperature of the salt. This means that a major portion of the salt

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would not freeze during discharging and the high latent portion of the stored heat can not be extracted from the storage. Consequently, the utilization factor of the system would be relatively low.

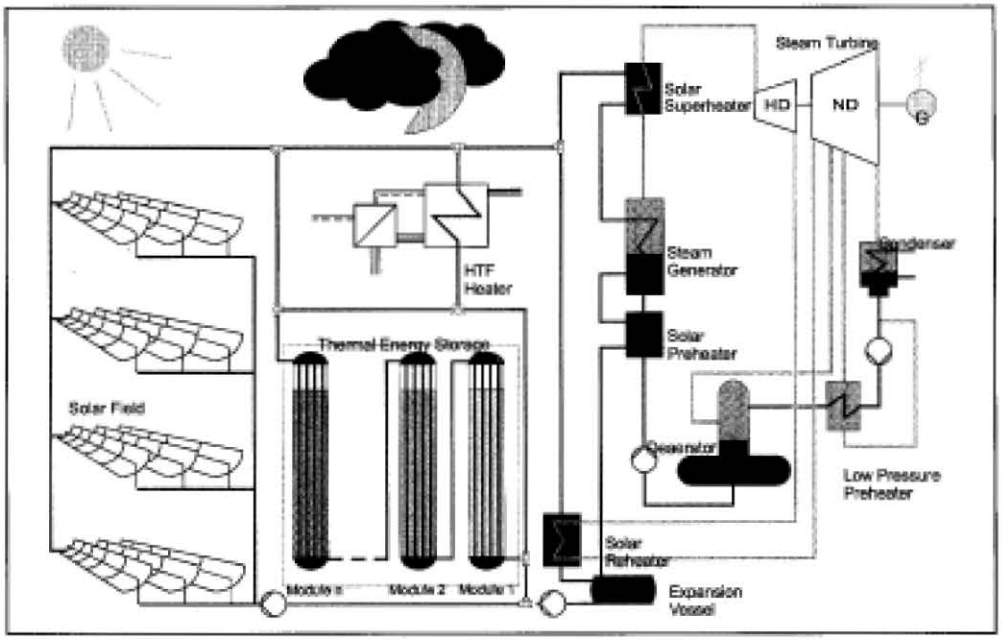

Figure 7. Possible process scheme of a SEGS with integrated PCM-TES (Michels and Hahne 1996)

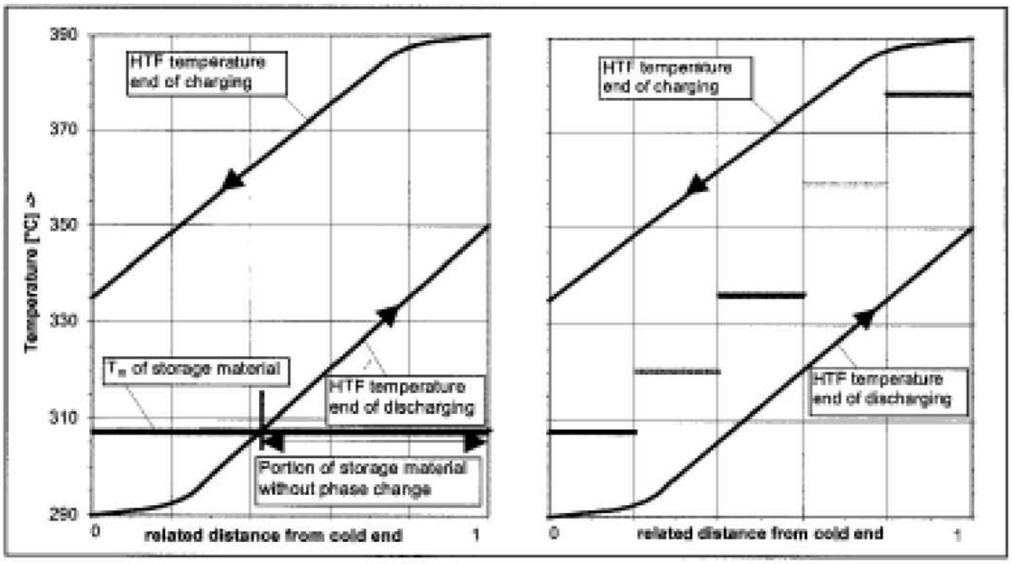

Figure 8. Theoretical temperature distribution in a PCM-TES for SEGS

The latent heat can only be used completely if, during charging, the temperature of the HTF is always higher than the melting point of the storage medium and, during discharging, always lower. This is shown in the right-hand diagram of Figure 8. According to Michels, five different PCMs have to be used for an optimized storage operating in the temperature range of a SEGS plant.

Michels experimentally investigated a configuration of three different modules connected in series (Michels and Hahne 1996). He used the nitrates KNO_3, KNO_3/KCl and $NaNO_3$. Figure 9 shows the measured temperature distribution in the test modules during charging.

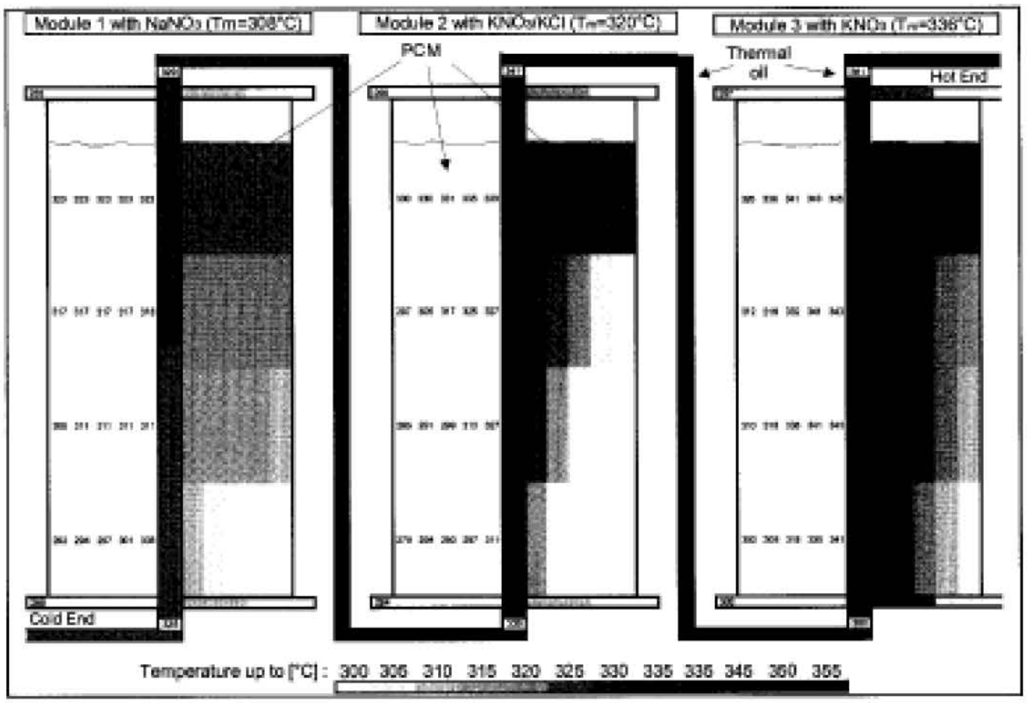

Figure 9. Temperature distribution inside the cascaded PCM test modules during charging

In his experiments, Michels proved the high utilization factor of a cascaded PCM storage. However additional experiments are required to verify the feasibility of a five-stage cascaded storage. Also additional design studies have to be performed to optimize the sizes of each stage, to select the appropriate material for the storage tank for each salt and to evaluate the cost.

Further works are concerned with PCM as storage material for parabolic troughs with Direct Steam Generation (Solomon 1991) and with the development of special measurement devices to observe the phase-change (Jaworske 1991).

A combined configuration of one sensible heat storage module, like concrete, and of two PCM modules at each end as proposed by Ratzesberger et al. (1994) seems to be a reasonable approach as a next step in the development of PCM storage.

3.3.1.4 Chemical Energy Storage

In the SERI workshop it was concluded that chemical energy storage is an attractive option in longer term and may offer relatively low cost. Based on a preliminary cost assessment the hydroxide/oxide reaction between CaO and H_2O was mentioned as one possibility (NASA 1979).

Subsequently, the Pacific Northwest Laboratory (PNL—now the Pacific Northwest National Laboratory—PNNL) conducted a study funded by the U.S. Department of

Energy to investigate the potential feasibility for a chemical energy storage based on this reaction. The report (Brown et al. 1991) concluded that this type of storage is, in principle, applicable under the SEGS temperature conditions. However, the study was based only on theoretical analysis and basic experimental investigations, and information was somewhat limited due to proprietary restrictions. The authors could not determine if the dynamics of the reaction fit to the requirements of storage for solar power plants, and also concluded that the question of proper integration into the solar power system remained unsolved. Costs were roughly estimated to be about $45/kWh. No further development of this type of storage could be identified through the literature review, and it appears that considerable work is required to develop a chemical energy storage system with hydroxide/oxide reaction for commercial application.

Development of another type of chemical storage seems to be much advanced, namely the solar ammonia energy storage developed by the Australian National University (Kreetz and Lovegrove 1999, Lovegrove et al. 1999, and Luzzi et al.). In this system, liquid ammonia is dissociated in a solar reactor into hydrogen and nitrogen. The energy is recovered in an ammonia synthesis reactor. The ammonia system was developed for use with parabolic dishes, but theoretically can also be used in the temperature range of parabolic trough collectors.

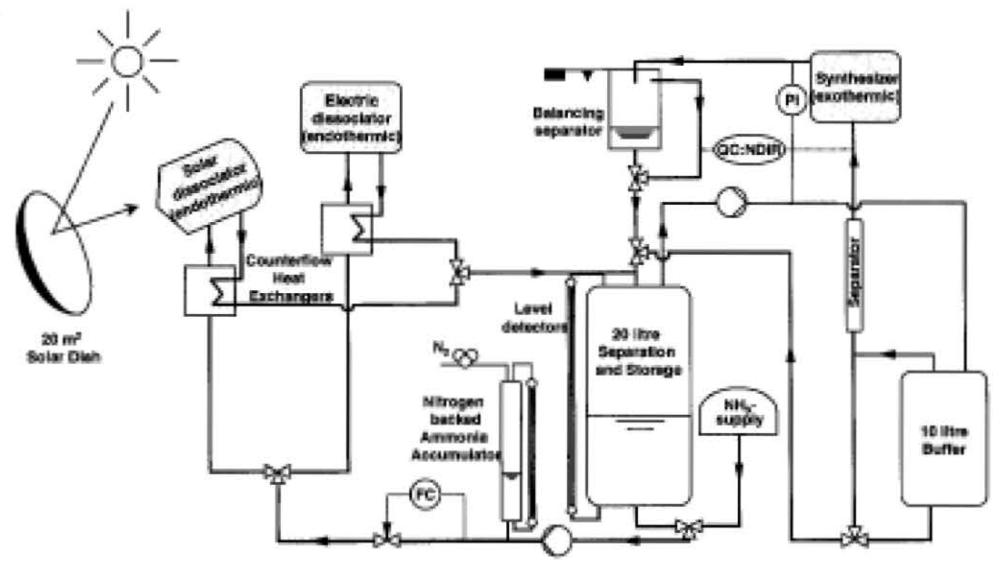

Figure 10. Test loop set up for solar ammonia energy storage (Lovegrove et al. 1999)

The first small-scale solar test facility was set up and has been operating for more than a year. Figure 10 shows the flow diagram of the test installation. The nominal solar input into the system is 1 kW. At this scale, it is clear that potential scale-up to a multi-megawatt system would be a significant undertaking.

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Current estimates are that a 10-MW plant built largely from industry standard or proven components will cost about $100 million (U.S. 1999) (Luzzi et al.).

4.0 Observations and Recommendations

Based on the body of literature examined in this survey, we come to the following observations:

- There have been no *major* bold developments in the field of thermal energy storage systems for trough power plants in the 1990s compared to prior work. However, there have been important contributions furthering work on candidate systems previously identified.
- Within the context of the Solar Two project, a prototype two-tank molten salt system containing a nitrate salt eutectic was successfully tested over a 11/2 year testing period.
- Molten salt systems with lower melting points should be explored for trough applications. The two-tank system as implemented at Solar Two is a relatively low-risk approach. A one-tank thermocline system is riskier with respect to performance, but offers the promise of important cost reductions.
- Useful laboratory-scale testing on several PCM modules was carried out by ZSW. The results substantiate the prior conclusion that these systems offer promise, and further work appears warranted.
- A proposal for prototype construction and testing of 1–2-MWh prototype concrete-steel storage system was submitted to the European Union in the summer of 1999. Present indications at the issuance of this report are that funding for this project will not be granted in the current round of accepted projects, and resubmission in early 2000 is anticipated.
- We found no evidence that the design and development of chemical storage for parabolic trough applications has been *significantly* advanced in the last decade, though some further useful evaluations have been carried out.

These observations lead us to the following recommendations:

1. On the basis of current progress and cost estimates, molten salts and concrete systems merit priority as candidates for near-term deployment. PCM systems are the additional system of choice for longer-term development.
2. The focus of near-term research should be prototype system development and field implementation to refine designs and provide the bases for valid performance and cost estimates.

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APPENDIX A:
Report of Database Search

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ENERGY FILE SEARCH STATISTICS - P337407K 03 DEC 1999 15:03:04 PAGE 2

THERM. ENERGIESPEICHERUNG

29 ANSWERS PRINTED IN FORMAT "ALL"
IN FILE "ENERGY"
USING QUERY:

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L1        6747 SEA FILE=ENERGY THERMAL ENERGY STORAGE EQUIPMENT/CT
L2        4027 SEA FILE=ENERGY 1427/CC
L3        1873 SEA FILE=ENERGY L1 AND L2
L4      189376 SEA FILE=ENERGY ("POWER PLANTS"/CT OR "DUAL-PURPOSE POWER
               PLANTS"/CT OR "FUEL CELL POWER PLANTS"/CT OR "GAS TURBINE
               POWER PLANTS"/CT OR "HYDROELECTRIC POWER PLANTS"/CT OR
               "HIGH-HEAD HYDROELECTRIC POWER PLANTS"/CT OR "LOW-HEAD
               HYDROELECTRIC POWER PLANTS"/CT OR "MEDIUM-HEAD HYDROELECTRIC
               POWER PLANTS"/CT OR "MICRO-SCALE HYDROELECTRIC POWER
PLANTS"/CT
                OR "PUMPED STORAGE POWER PLANTS"/CT OR "SMALL-SCALE
HYDROELECT
               RIC POWER PLANTS"/CT OR "MHD POWER PLANTS"/CT OR "MHD
GENERATOR
                ETF"/CT OR "PEAKING POWER PLANTS"/CT OR "COMPRESSED AIR
               STORAGE POWER PLANTS"/CT OR "PUMPED STORAGE POWER
PLANTS"/CT
               OR "SOLAR POWER PLANTS"/CT OR "OCEAN THERMAL POWER
PLANTS"/CT
               OR "ORBITAL SOLAR POWER PLANTS"/CT OR "PHOTOVOLTAIC POWER
               PLANTS"/CT OR "SALINITY GRADIENT POWER PLANTS"/CT OR "SOLAR
               THERMAL POWER PLANTS"/CT OR "DISTRIBUTED COLLECTOR POWER
               PLANTS"/CT OR "TOWER FOCUS POWER PLANTS"/CT OR "BARSTOW
SOLAR
               PILOT PLANT"/CT OR "THERMAL POWER PLANTS"/CT OR
"COMBINED-CYCLE
                POWER PLANTS"/CT OR "MHD GENERATOR ETF"/CT OR "FOSSIL-FUEL
               POWER PLANTS"/CT OR "KINGSTON STEAM PLANT"/CT OR "PARADISE
               STEAM PLANT"/CT OR "SHAWNEE STEAM PLANT"/CT OR "WIDOWS
CREEK
               STEAM PLANT"/CT OR "GEOTHERMAL POWER PLANTS"/CT OR "NUCLEAR
               POWER PLANTS"/CT OR "RSPSSAR STANDARD PLANT"/CT OR "EBASCO
               STANDARD PLANT"/CT OR "GIBBSSAR STANDARD PLANT"/CT OR
"OFFSHORE
                NUCLEAR POWER PLANTS"/CT OR "SWESSAR STANDARD PLANT"/CT
OR
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ENERGY FILE SEARCH STATISTICS - P337497K 03 DEC [illegible] [illegible] PAGE 3

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                 "UNDERGROUND NUCLEAR STATIONS"/CT OR "OCEAN THERMAL POWER
                 PLANTS"/CT OR "REFUSE-FUELED POWER PLANTS"/CT OR "SOLAR
                 THERMAL POWER PLANTS"/CT OR "DISTRIBUTED COLLECTOR POWER
                 PLANTS"/CT OR "TOWER FOCUS POWER PLANTS"/CT OR "BARSTOW
SOLAR
                 PILOT PLANT"/CT OR "WOOD-FUEL POWER PLANTS"/CT OR
"THERMONUCLEA
                 R POWER PLANTS"/CT OR "TIDAL POWER PLANTS"/CT OR
"KISLOGUBSK
                 POWER PLANT"/CT OR "PASSAMAQUODDY POWER PLANT"/CT OR
"RANCE
                 POWER PLANT"/CT OR "WIND POWER PLANTS"/CT OR "SFD WIND
                 GENERATORS"/CT)
L5           245 SEA FILE=ENERGY L3 AND L4
L7            36 SEA FILE=ENERGY L5 AND PY>=[illegible]
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A-2

APPENDIX B:

Abstracts of Selected References

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 5

L7 ANSWER 2 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1996(3):15026 ENERGY
TI Development and investigation of thermal energy storage systems for the medium temperature range.
AU Steiner, D.; Groll, M. (Univ. Stuttgart (Germany). Inst. fuer Kernenergetik und Energiesysteme);
Wierse, M. (Forschungsinstitut fuer Kerntechnik und Energiewandlung e.V., Stuttgart (Germany))
NR CONF-950729-
SO Proceedings of the 30. intersociety energy conversion engineering conference. Volume 2.
Editor(s): Goswami, D.Y. (Univ. of Florida, Gainesville, FL (United States)); Kannberg, L.D.; Somasundaram, S. (Pacific Northwest Lab., Richland, WA (United States)); Mancini, T.R. (Sandia National Labs., Albuquerque, NM (United States))
New York, NY: American Society of Mechanical Engineers, 1995. p. 193-198 of 658 p.
American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, NY 10017 (United States).
Conference: 30. Intersociety energy conversion conference, Orlando, FL (United States), 30 Jul
- 5 Aug 1995
DT Book Article; Conference
CY United States
LA English
FA AB
AB Within the frame of two projects funded by the German Federal Ministry for Research and Technology (BMFR) a thermochemical energy storage system for solar application and a sensible/latent hybrid storage system for industrial application were investigated. The thermochemical energy storage system utilizes the heat of reaction of the reversible reaction of magnesium and hydrogen. The operation temperature range is between 280 C and 480 C.
The storage capacity amounts to about 54 MJ. The combination of the MgH_2/Mg system with an appropriate low-temperature alloy/hydride offers the option of producing cold below 0 C in the heat retrieval cycle. The hybrid storage system uses a salt/ceramic which consists of a micro-porous MgO matrix, the pores of which are filled with a salt (85 wt% $NaNO_3$, 15 wt% $NaNO_2$). The sensible heat of both the ceramic and the salt and the phase change enthalpy of the salt in the temperature range 250 C to 290 C can be utilized. The experimental storage bed was operated in the temperature range of 150 C to 450 C, the storage capacity was about 400 MJ. Air was used as the heating and cooling heat transfer medium
CC *250600; 142000
CT DESIGN; LATENT HEAT STORAGE; MAGNESIUM HYDRIDES; MAGNESIUM OXIDES; NITRITES;
PERFORMANCE; SENSIBLE HEAT STORAGE; SODIUM COMPOUNDS; SODIUM NITRATES; SOLAR
THERMAL POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT; THERMOCHEMICAL HEAT
STORAGE; WASTE HEAT UTILIZATION
*THERMAL ENERGY STORAGE EQUIPMENT: -DESIGN; -THERMAL ENERGY STORAGE EQUIPMENT: -PERFORMANCE; -SOLAR THERMAL POWER PLANTS: -THERMOCHEMICAL HEAT
L7 ANSWER 2 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
STORAGE
BT ALKALI METAL COMPOUNDS; ALKALINE EARTH METAL COMPOUNDS; CHALCOGENIDES; ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; HEAT
STORAGE; HYDRIDES; HYDROGEN COMPOUNDS; MAGNESIUM COMPOUNDS; NITRATES; NITROGEN
COMPOUNDS; OXIDES; OXYGEN COMPOUNDS; POWER PLANTS; SODIUM COMPOUNDS; SOLAR

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 9

L7 ANSWER 4 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1995(16):102317 ENERGY
TI Storing solar energy in salt.
AU Valenti, M.
SO Mechanical Engineering (United States) (Jun 1995) v. 117(6) p. 72-75.
CODEN: MEENAH ISSN: 0025-6501
DT Journal
CY United States
LA English
FA AB
AB This article describes the world's largest power tower incorporating one of the newest commercial solar energy systems and being build in California's Mojave Desert. The project — sponsored by the Department of Energy (DOE) and a consortium of western utilities, municipalities, and associations — is called Solar Two, and it will use molten salt to absorb solar energy and store that energy until it is needed to generate electricity. Construction will be completed on Solar Two in September. Solar thermal systems convert the sun's rays into electricity by using a thousand or more dual-axis, sun-tracking mirrors, called heliostats, to focus optimum sunlight on the solar receiver of a power tower containing a working fluid. The fluid is heated to a desired temperature and sent to a storage facility. During periods of peak demand, the fluid is circulating through heat exchangers to generate steam used to drive a turbine
CC *142000; 140702
CT CENTRAL RECEIVERS; HYBRID SYSTEMS; MOLTEN SALTS; PHYSICAL PROPERTIES; THERMAL
ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS
•TOWER FOCUS POWER PLANTS: -THERMAL ENERGY STORAGE EQUIPMENT; "MOLTEN SALTS: -PHYSICAL PROPERTIES
BT ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; POWER PLANTS; SALTS; SOLAR
POWER PLANTS; SOLAR RECEIVERS; SOLAR THERMAL POWER PLANTS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 10

L7 ANSWER 5 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1995(6>:50639 ENERGY
TI Investigation of commercial central receiver thermal storage and steam generator issues.
AU Kelly, B.O.; Lessley, R.L. (Bechtel Corp., San Francisco, CA (United States))
NR CONF-940326-
SO Solar engineering 1994.
Editor(s): Klett, D.E.; Hogan, R.E.; Tanaka, Tadayoshi
New York, NY: American Society of Mechanical Engineers. 1994. p. 611-616 of 670 p.
American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, 10017 (United States).
Conference: ASME/JSME/JSES international solar energy conference, San Francisco, CA (United States), 27-30 Mar 1994
ISBN: 0-7918-1192-1
DT Book Article; Conference
CY United States
LA English
FA AB
AB Conceptual designs, cost estimates, and warranty provisions were developed for nitrate salt steam generators and thermal storage system hot salt tanks in the initial 100 MWe commercial central receiver power plants. All of the steam generator designs, including the U-tube/U-shell, straight tube/straight shell, and U-tube/kettle boiler, offered comparable steady state and transient performance and competitive cost estimates. The hot salt tank designs included <1) a stainless steel tank with external insulation and (2) a carbon steel tank with
internal refractory insulation and a corrugated Incoloy liner to isolate the salt from the refractory. The stainless steel tank designs had both lower heat losses and lower capital costs
CC *140702; 142000; 360104
CT COMMERCIALIZATION; COMPARATIVE EVALUATIONS; FEASIBILITY STUDIES; HEAT LOSSES; MATERIALS TESTING; PERFORMANCE; STEAM GENERATORS; THERMAL ANALYSIS; THERMAL ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS
*TOWER FOCUS POWER PLANTS: COMMERCIALIZATION; *STEAM GENERATORS: +FEASIBILITY STUDIES; -THERMAL ENERGY STORAGE EQUIPMENT: -FEASIBILITY STUDIES
BT BOILERS; ENERGY LOSSES; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; EVALUATION; LOSSES; POWER PLANTS; SOLAR POWER PLANTS; SOLAR THERMAL POWER PLANTS; TESTING; THERMAL POWER PLANTS; VAPOR GENERATORS
ET U

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 11

L7 ANSWER 6 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE

AN 1995(8):50627 ENERGY
TI Attenuation thermal energy storage in sensible-heat solar-dynamic receivers.
AU Lund, K.O. (Univ. of California. La Jolla, CA (United States). Center for Energy and Combustion Research)
NR CONF-940326-
SO Solar engineering 1994.
Editors): Klett, D.E.; Hogan, R.E.; Tanaka, Tadayoshi
New York, NY: American Society of Mechanical Engineers. 1994. p. 273-281 of 670 p.
American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, 10017 (United States).
Conference: ASME/JSME/JSES international solar energy conference, San Francisco, CA (United States), 27-30 Mar 1994
ISBN: 0-7918-1192-1
DT Book Article; Conference
CY United States
LA English
FA AB
AB Solar dynamic receiver designs are investigated and evaluated for possible use with sensible energy storage in single-phase materials. The designs are similar to previous receivers having axial distribution of concentrated solar input flux, but differ in utilizing axial conduction in the storage material for attenuation of the solar flux "signal", and in having convective beat removal at the base of the receiver. One-dimensional, time-dependent heat transfer equations are formulated for the storage material temperature field, including radiative tosses to the environment, and a general heat exchange effectiveness boundary condition at the base. The orbital periodic input solar flux is represented as the sum of steady and oscillating components, with the steady component solved numerically subject to specified receiver thermal efficiency. For the oscillating components the Fast Fourier Transform algorithm (FFT) is applied, and the complex transfer function of the receiver is obtained and evaluated as a filter for the input flux spectrum. Inverse transformation, result in the amplitudes and mode shapes of the oscillating temperatures. By adjustment of design parameters, the amplitude of the oscillating component of the outlet gas temperature is limited to an acceptable magnitude. The overall result of the investigation is the dependence of the receiver M×c product (mass times specific beat) on the conduction transfer units, which leads to lower weight designs than comparable previous single and two phase designs, when all constraints are included. As these designs also offer improvements in cost reduction and reliability they warrant further detailed investigation
CC *140700; 142000
CT DESIGN; MATHEMATICAL MODELS; PERFORMANCE; SENSIBLE HEAT STORAGE; SOLAR RECEIVERS; SOLAR THERMAL POWER PLANTS; SPACECRAFT POWER SUPPLIES; THERMAL ENERGY STORAGE EQUIPMENT
L7 ANSWER 6 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
*SOLAR RECEIVERS: -DESIGN; *SOLAR RECEIVERS: -SENSIBLE HEAT STORAGE; *SOLAR THERMAL POWER PLANTS: -DESIGN; -SPACECRAFT POWER SUPPLIES: -DESIGN
BT ELECTRONIC EQUIPMENT; ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS;
EQUIPMENT; HEAT STORAGE; POWER PLANTS; POWER SUPPLIES; SOLAR POWER PLANTS; STORAGE; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 13

L7 ANSWER 7 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1995(7):41657 ENERGY
TI Thermal energy storage at medium and high temperatures for solar power plants.
Thermische Energiespeicherung bei mittleren und hohen Temperaturen fuer Solarkraftwerke.
AU Hunold, D. (Geschaeftsbereich Solarthermische Energietechnik des Zentrums fuer Sonnenenergie- und Wasserstoff-Forschung Baden-Wuerttemberg (ZSW), Stuttgart (Germany)); Tamme, R. (Fachgruppe Thermische und Chemische Speicher in der Deutschen Forschungsanstalt fuer Luft-
und Raumfahrt (DLR), Stuttgart (Germany))
SO Forschungsverbund Sonnenenergie. Topics 93/94. Solar thermal power. Thermal uses of solar energy.
Forschungsverbund Sonnenenergie. Themen 93/94. Solarthermie. Thermische Nutzung der Solarenergie.
Compiler: Hertlein, H.P.
Forschungsverbund Sonnenenergie, Koeln (Germany) (9204591)
Feb 1994. p. 75-82 of 98 p. Available from FIZ Karlsruhe.
ISBN: 0939-7582
DT Miscellaneous; Availability Note
CY Germany, Federal Republic of
LA German
FA AB; ABDE
AB The current R and D activities in the field of medium and high temperature storage are presented and the storage test facilities of ZSW and DLR briefly described. The R and D activities include studies on heat transfer processes in alkali metal nitrates used as phase-change storage material for the medium temperature range with different geometries of the heat exchanger, as well as investigations of different salt ceramic hybrid materials for high temperature applications. The state of development of medium and high temperature
storage systems is shown, possible constructions of storage systems are presented, and an outlook on further studies is provided. (orig.)
CC *142000; 140700
CT COMPARATIVE EVALUATIONS; DESIGN; ECONOMICS; ENERGY STORAGE; FLOWSHEETS; FORECASTING; HEAT EXCHANGERS; HEAT TRANSFER; PHASE CHANGE MATERIALS; SOLAR
POWER PLANTS; TECHNOLOGY UTILIZATION; THERMAL ENERGY STORAGE EQUIPMENT; WORKING FLUIDS
-ENERGY STORAGE: -SOLAR POWER PLANTS
BT DIAGRAMS; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; ENERGY TRANSFER; EQUIPMENT;
EVALUATION; FLUIDS; MATERIALS; POWER PLANTS; STORAGE
ET D; Es

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 17

L7 ANSWER 10 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1994(2):12158 ENERGY
TI Storage of solar high temperature heat.
Speicherung solarer Hochtemperaturwaerme.
AU Meier, A.; Winkler, C. (Paul Scherrer Inst. (PSI), Villigen (Switzerland))
CS Paul Scherrer Inst. (PSI), Villigen (Switzerland) (5107100)
NR PSI-93-07
SO Dec 1993. 62 p. OSTI as DE94726403; NTIS.
ISBN: 1019-0643
DT Report; Numerical Data
CY Switzerland
LA German
FA AB
AB Based on a mathematical-physical model for the description of sensible heat storage in packed beds, the simulation program PACKBED has been developed, which is intended to serve as a decision base for the assessment of packed bed storage systems used in solar high temperature applications. For the validation of the theoretical model, the thermodynamic behaviour of packed beds consisting of sensible heat storage material has been investigated in the experimental store ARIANE. using air as heat transfer medium. Different material tests in the temperature range up to 800oC have been carried out. The short-time storage in large scale solar thermal power plants has been simulated under real operating conditions, as they are expected for the planned 30 MWe PHOEBUS solar tower power plant. For the same storage, it has been shown that the pressure drop, and therefore the required pumping power of the fan, can be reduced significantly by introducing an air bypass system. For the characterization of the storage performance, a storage quality factor has been introduced, which allows to compare different sensible heat storage systems and to describe the degradation of such storage systems during consecutive charging/discharging cycles. In the field of latent heat storage, a thorough literature research has been performed. With a new simulation program for large scale latent heat storage systems, parameter studies have been performed in order to clarify the suitability of latent storage material for storing solar high temperature heat in packed beds. (author) 22 figs., 7 tabs., 88 refs.
CC *142000; 140702
CT COMPUTERIZED SIMULATION; EXPERIMENTAL DATA; LATENT HEAT STORAGE; MATHEMATICAL MODELS; P CODES; PACKED BEDS; PARAMETRIC ANALYSIS; SENSIBLE HEAT STORAGE; SOLAR ENERGY; TEMPERATURE RANGE 0273-0400 K; TEMPERATURE RANGE 0400-1000 K; THEORETICAL DATA; THERMAL ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS; VALIDATION
*SOLAR ENERGY: -SENSIBLE HEAT STORAGE; -THERMAL ENERGY STORAGE EQUIPMENT: *PACKED BEDS
BT COMPUTER CODES; DATA; ENERGY; ENERGY SOURCES; ENERGY STORAGE; EQUIPMENT; HEAT STORAGE; INFORMATION; NUMERICAL DATA; POWER PLANTS; RENEWABLE ENERGY SOURCES; SIMULATION; SOLAR POWER PLANTS; SOLAR THERMAL POWER PLANTS; STORAGE; TEMPERATURE RANGE; TESTING; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 21

L7 ANSWER 13 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(21):156481 ENERGY
TI A solar energy-based direct steam generation method using latent heat thermal energy storage.
AU Solomon, A.D. (Univ. of Tennessee, Knoxville (United States))
NR CONF-910277—
SO WATTec '91. The technical professional: Staying current/staying competitive.
Anon.
Oak Ridge, TN: Sun Graphics Inc. 1991. p. 67-68 of 80 p. Sun Graphics Inc., 101 East Tyrone Rd., Oak Ridge, TN 37830 (United States).
Conference: 18. annual WATTec interdisciplinary technical conference and exhibition, Knoxville, TN (United States), 19-22 Feb 1991
DT Book Article; Conference
CY United States
LA English
FA AB
AB The heart of a solar-energy based electricity generation approach is a direct steam generation (DSG) unit consisting of tube banks, embedded in a phase changing material (PCM). During times of high solar energy availability steam is pumped through the tubes, releasing heat to the PCM which takes it up as the latent heat of melting and undergoes a phase change to its liquid phase. This period is referred to as the charging period. The discharge period is marked by water being pumped through the tubes; now heat is transferred from the PCM to the water which, under appropriate conditions, will boil and emerge as steam. The process of heat exchange between the water or steam in the tube (during charge and discharge) and the PCM is a complex one governed by a variety of factors including tube size, pressure drops, quality of the two phase flow region, extent of this region, and flow rates. In order to examine the performance of such a DSG unit a computer code simulating two phase flow, heat exchange between tube and PCM, and heat transfer and phase change in the PCM has been prepared. The code permits the user to vary all major geometric and thermophysical parameters; options include variable tube diameter, angle of inclination and different flow directions during charge and discharge. In this paper the author describes the above code, examining its underlying assumptions and algorithms. Among points raised are the role of natural convection in the melt. Results shown include sample runs and simple analytical approximations for key performance factors. In addition he describes preliminary experimental work being done to verify the computer model.
CC *140700; 142000
CT COMPUTERIZED SIMULATION; HEAT TRANSFER; PERFORMANCE; PHASE CHANGE MATERIALS; PHASE TRANSFORMATIONS; SOLAR THERMAL POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT
*SOLAR THERMAL POWER PLANTS: -THERMAL ENERGY STORAGE EQUIPMENT; -THERMAL ENERGY STORAGE EQUIPMENT: -COMPUTERIZED SIMULATION
BT ENERGY TRANSFER; EQUIPMENT; MATERIALS; POWER PLANTS; SIMULATION; SOLAR POWER PLANTS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 23

L7 ANSWER 14 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(20):149792 ENERGY
TI Energy storage.
AU Anon.
SO Cool energy. Renewal solutions to environmental problems.
Brower, M.
Cambridge, MA: Massachusetts Inst. of Tech. Press. 1992. p. 155-172 of 225 p. MIT Press, Massachusetts Institute of Technology, Cambridge, MA 02142 (United States).
Book Article
CY United States
LA English
FA AB
AB This chapter discusses the role that energy storage may have on the energy future of the US. The topics discussed in the chapter include historical aspects of energy storage, thermal energy storage including sensible heat storage, latent heat storage, thermochemical heat storage, and seasonal heat storage, electricity storage including batteries, pumped hydroelectric storage, compressed air energy storage, and superconducting magnetic energy storage, and production and combustion of hydrogen as an energy storage option.
CC *250000; 142000; 290301; 299000; C5700
CT COMPRESSED AIR ENERGY STORAGE EQUIPMENT; COMPRESSED AIR STORAGE POWER PLANTS; ECONOMICS; ELECTRIC BATTERIES; ELECTRIC-POWERED VEHICLES; ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENVIRONMENTAL IMPACTS; HYDROGEN FUEL CELLS; HYDROGEN PRODUCTION; HYDROGEN STORAGE; LEAD-ACID BATTERIES; MAGNETIC ENERGY STORAGE EQUIPMENT; OFF-PEAK ENERGY STORAGE; PEAKING POWER PLANTS; SUPERCONDUCTING COILS; SUPERCONDUCTING MAGNETS; TECHNOLOGY ASSESSMENT; THERMAL ENERGY STORAGE EQUIPMENT; UNDERGROUND STORAGE
*ENERGY STORAGE SYSTEMS: -ECONOMICS; -ENERGY STORAGE SYSTEMS: -ENVIRONMENTAL IMPACTS; -ENERGY STORAGE SYSTEMS: -TECHNOLOGY ASSESSMENT
BT DIRECT ENERGY CONVERTERS; ELECTRIC BATTERIES; ELECTRICAL EQUIPMENT; ELECTROCHEMICAL CELLS; ELECTROMAGNETS; ENERGY STORAGE; EQUIPMENT; FUEL CELLS; MAGNETS; PEAKING POWER PLANTS; POWER PLANTS; STORAGE; SUPERCONDUCTING DEVICES; VEHICLES

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 27

L7 ANSWER 17 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(10):67921 ENERGY
TI Observations of the freeze/thaw performance of lithium fluoride by motion picture photography.
AU Jaworske, D.A. (National Aeronautics and Space Administration, Cleveland, OH (United States). Lewis Research Center); Perry, W.D. (Auburn Univ., AL (United States). Dept. of Chemistry)
NR CONF-910801—
SO Proceedings of the 26th intersociety energy conversion engineering conference. Volume 4. Anon.
La Grange Park, IL: American Nuclear Society. 1991. p. 151-154 of 575 p. American Nuclear Society, 555 North Kensington Ave., La Grange Park, IL 60525 (United States).
Conference: 26. intersociety energy conversion engineering (IECE) conference, Boston, MA (United States), 3-9 Aug 1991
ISBN: 0-89448-163
DT Book Article; Conference
CY United States
LA English
FA AB
AB Molten salts are attractive candidates for thermal energy storage in solar dynamic power systems owing to their high latent heat of fusion. This paper reports that, to gain direct observation of the molten salt phase change, a novel containerless technique was developed where the high surface tension of lithium fluoride was used to suspend a bead of the molten salt inside a specially designed wire cage. By varying the current passing through the wire, the cage also served as a variable heat source. In this way, the freeze/thaw performance of the lithium fluoride could be photographed by motion picture photography without the influence of container walls. The motion picture photography of the lithium fluoride sample revealed several zones during the phase change, a solid zone and a liquid zone, as expected, and a slush zone that was predicted by thermal analysis modeling.
«250600; 142000; 140700; 360204
FUSION HEAT; LATENT HEAT STORAGE; LITHIUM FLUORIDES; MATERIALS TESTING; MOLTEN SALTS; PERFORMANCE TESTING; PHASE CHANGE MATERIALS; SOLAR THERMAL POWER PLANTS; THERMAL ANALYSIS; THERMAL ENERGY STORAGE EQUIPMENT
-LATENT HEAT STORAGE: -THERMAL ENERGY STORAGE EQUIPMENT; -MOLTEN SALTS: -FUSION HEAT; -LITHIUM FLUORIDES: -THERMAL ANALYSIS; -LITHIUM FLUORIDES: -PERFORMANCE TESTING
ALKALI METAL COMPOUNDS; ENERGY STORAGE; ENTHALPY; EQUIPMENT; FLUORIDES; FLUORINE COMPOUNDS; HALIDES; HALOGEN COMPOUNDS; HEAT STORAGE; LITHIUM COMPOUNDS; LITHIUM HALIDES; MATERIALS; PHYSICAL PROPERTIES; POWER PLANTS; SALTS; SOLAR POWER PLANTS; STORAGE; TESTING; THERMAL POWER PLANTS; THERMODYNAMIC PROPERTIES; TRANSITION HEAT

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ENERGY FILE SEARCH RESULTS - P337407X 03 DEC 1999 15:03:04 PAGE 30

L7 ANSWER 20 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(5):26741 ENERGY
TI C.R.S. receiver and storage systems evaluation.
AU Castro, M.; Presa, J.L.; Diaz, J.; Peire, J. (Univ. Politecnia de Madrid (Spain)); Faas, S.E.; Radosevich, L.G.; Skinrood. A.C. (Sandia National Labs. Livermore, CA (United States))
SO Solar Energy (Journal of Solar Energy Science and Engineering) (United States) (1991) v. 47(3) p. 197-207.
CODEN: SRENA4 ISSN: 0038-092X
DT Journal
CY United States
LA English
FA AB
AB This article describes a comparison and evaluation of the Solar One and CESA-I receiver and thermal storage systems. The evaluation is based on operating data from Solar One, the MWe experimental solar central receiver plant located near Barstow, California, USA and CESA-I, the 1.2 MWe experimental solar central receiver plant located near Almeria, Spain. This study was sponsored by the US-Spain Joint Committee for Scientific and Technological Cooperation. Significant differences exist in the design and operation of the receiver and thermal storage systems for the two experimental plants. An evaluation of their performance has increased our understanding of the plant design variables and provides useful information to improve the designs of future central receiver plants.
*140702; 142000
CALIFORNIA; CENTRAL RECEIVERS; COMPARATIVE EVALUATIONS; DESIGN; EVALUATION; INTERNATIONAL COOPERATION; PERFORMANCE; SPAIN; THERMAL ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS
*TOWER FOCUS POWER PLANTS: *EVALUATION
COOPERATION; DEVELOPED COUNTRIES; DEVELOPING COUNTRIES; EQUIPMENT; EUROPE; EVALUATION; NORTH AMERICA; POWER PLANTS; SOLAR POWER PLANTS; SOLAR RECEIVERS; SOLAR THERMAL POWER PLANTS; THERMAL POWER PLANTS; USA
ET I

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 31

L7 ANSWER 21 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1991(20>:132341 ENERGY
TI Large energy storage facilities (200 mWh th) for medium-temperature-range solar power stations.
Grosse Energiespeicher (200 MWh th) fuer Solarkraftwerke im Mitteltemperaturbereich.
AU Beine, B. (Siempelkamp Giesserei GmbH und Co., Krefeld (Germany, F.R.))
NR CONF-901033—
SO 7th international solar energy forum. Energy-use efficiency and harnessing of renewable energy sources at the regional and municipal levels. What can be their contribution towards averting the threat to the climate? Conference report. Vol. 3.
7. Internationales Sonnenforum. Rationelle Energieverwendung und Nutzung erneuerbarer Energiequellen im regionalen und kommunalen Bereich. Welchen Beitrag koennen sie zur Abwehr der Klimabedrohung leisten? Tagungsbericht. Bd. 3.
Deutsche Gesellschaft fuer Sonnenenergie e.V. (DGS), Muenchen (Germany) (9201294)
Muenchen: DGS-Sonnenenergie Verlags-GmbH. 1990. p. 1680-1685 of 769 p.
Conference: 7. international solar forum: rational use of energy a"d "se of renewable resources of energy in regional and municipal domains. 7. Internationales Sonnenforum: Rationelle Energieverwendung und Nutzung Erneuerbarer Energiequellen im Regionalen und Kommunalen Bereich - Welchen Beitrag Koennen Sie zur Abwehr der Klimabedrohung Leisten, Frankfurt am Main (Germany), 9-12 Oct 1990
DT Book Article; Conference
CY Germany, Federal Republic of
LA German
FA AB; ABDE
AB The objective of the study was to find a thermal energy storage unit for a medium-temperature solar power station in the temperature range between 200deg C and 400deg C requiring investment cost of less than 25 US Dollar/kWh of exploitable thermal energy. The following storage types were compared: Hot-tank and cold-tank liquid salt storage unit with pumps and heat exchangers; thermal oil storage unit; concrete storage unit with cast-in pipes; solid salt slab storage unit with cast-in pipes, and liquid salt storage unit in cascade connection. A concrete storage unit will have to be preferred none the least for reasons of technical risks and fast erectibility. (BWI).
CC *142000; 140700
CT BOILERS; COMPARATIVE EVALUATIONS; CONCRETE BLOCKS; DESIGN; INVESTMENT; MEASURING METHODS; OPERATION; SOLAR THERMAL POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT
*SOLAR THERMAL POWER PLANTS: -THERMAL ENERGY STORAGE EQUIPMENT; -THERMAL ENERGY STORAGE EQUIPMENT: -INVESTMENT; -THERMAL ENERGY STORAGE EQUIPMENT: -COMPARATIVE EVALUATIONS
BT BUILDING MATERIALS; EQUIPMENT; EVALUATION; MATERIALS; POWER PLANTS; SOLAR POWER PLANTS; THERMAL POWER PLANTS
ET Ea

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 33

L7 ANSWER 22 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1991(20):132340 ENERGY
TI Solar power plant with thermo-chemical storage - progress in development.
Solarkraftwerk mit thermochemischem Speicher - Fortschritte in der Entwicklung.
AU Mitzel, M. (Bomin-Solar GmbH, Loerrach (Germany, F.R.)); Bogdanovic, B. (Max-Planck-Institut fuer Kohleforschung, Muelheim an der Ruhr (Germany, F.R.). Inst. fuer Kerntechnik und Energiewandlung e.V.); Ritter, A. (Max-Planck-Institut fuer Strahlenchemie, Muelheim an der Ruhr (Germany, F.R.))
NR CONF-901033—
SO 7th international solar energy forum. Energy-use efficiency a"d harnessing of renewable energy sources at the regional and municipal levels. What can be their contribution towards averting the threat to the climate? Conference report. Vol. 3.
7. Internationales Sonnenforum. Rationelle Energieverwendung und Nutzung erneuerbarer Energiequellen im regionalen und kommunalen Bereich. Welchen Beitrag koennen sie zur Abwehr der Klimabedrohung leisten? Tagungsbericht. Bd. 3.
Deutsche Gesellschaft fuer Sonnenenergie e.V. (DGS), Muenchen (Germany) (9201294)
Muenchen: DGS-Sonnenenergie Verlags-GmbH. 1990. p. 1674-1679 of 769 p.
Conference: 7. international solar forum: rational use of energy and use of renewable resources of energy in regional and municipal domains. 7. Internationales Sonnenforum: Rationelle Energieverwendung und Nutzung Erneuerbarer Energiequellen im Regionalen und Kommunalen Bereich - Welchen Beitrag Koennen Sie zur Abwehr der Klimabedrohung Leisten, Frankfurt am Main (Germany). 9-12 Oct 1990
DT Book Article; Conference
CY Germany.Federal Republic of
LA German
FA AB; ABDE
AB This papers describes the functional mode of a solar energy station using thermochemical storage based on magnesium hydride/magnesium which is being developed currently on commission by the Federal Minister for Research and Technology by a study group comprising Bomin Solar GmbH and Co. KG, Loerrach, Max-Planck Institut fuer Kohleforschung,
Muelheim a.d. Ruhr, Institut fuer Kerntechnik u. Energiewandlung e.V., Max-Planck-Institut fuer Strahlenchemie, Muelheim a.d. Ruhr. (orig.).
CC *142000; 140700
CT DESIGN; DIAGRAMS; ELECTRIC POWER; HYBRID SYSTEMS; HYDRIDES; OPERATION; PROCESS
HEAT; SOLAR CONCENTRATORS; SOLAR POWER PLANTS; TEMPERATURE DEPENDENCE;
THERMAL ENERGY STORAGE EQUIPMENT; THERMOCHEMICAL HEAT STORAGE
*SOLAR POWER PLANTS: THERMOCHEMICAL HEAT STORAGE
BT ENERGY; ENERGY STORAGE; EQUIPMENT; HEAT; HEAT STORAGE; HYDROGEN COMPOUNDS;
POWER; POWER PLANTS; SOLAR EQUIPMENT; STORAGE
ET Co

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 39

ANSWER 26 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
1990(14):100530 ENERGY
Thermal stratification in hot storage-tanks.
Kandari, A.M. (Kuwait Inst. for Scientific Research, Safat (KW). Energy Div.)
Applied Energy <UK) (1990) v. 35(4) p. 299-315.
CODEN: APENDX ISSN: 0306-2619
Journal
United Kingdom
English
AB
This experimental investigation was conducted as a support activity for the development at Sulaibiyah, which has a 22 m3 stratified tank to act as a buffer reservoir between the paraboloid-dish solar collector and the toluence turbine energy-conversion device. The results show that the disturbed zone is 1500 mm thick (i.e. nearly 30% of the usable tank height). Based on these results, an experimental model (1/25th scale by volume) was constructed to study the effect of using improved distributor header geometry and a settling mesh for reducing the buffer-zone thickness. Using the new header configuration, extraction efficiencies of 85% could be achieved, (author).
*142000
EFFICIENCY; SCALE MODELS; SOLAR THERMAL POWER PLANTS; STRATIFICATION; THERMAL ENERGY STORAGE EQUIPMENT
-THERMAL ENERGY STORAGE EQUIPMENT: -STRATIFICATION; -THERMAL ENERGY STORAGE EQUIPMENT: -SOLAR THERMAL POWER PLANTS
EQUIPMENT; POWER PLANTS; SOLAR POWER PLANTS; STRUCTURAL MODELS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 3

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L4	ANSWER 1 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN	1996(20):141769 ENERGY
TI	Regenerators in parabolic dish solar power stations. Regeneratoren in Parabolrinnen-Solarkraftwerken.
AU	Ratzesberger, R.
CS	Deutsche Forschungsanstalt fuer Luft- und Raumfahrt e.V. <DLR). Koein (Germany) (2143700) Funding Organisation: Bundesministerium fuer Forschung und Technologie, Bonn (Germany) (9200321)
SO	Thesis. Duesseldorf: VDI-Verl. 1995. 131 p. Ser. Title: Fortschritt-Berichte VDI. Reihe 6, Energietechnik, v. 330. ISBN: 3-18-333006-7 ISSN: 0178-9414
DT	Book; Dissertation
CY	Germany, Federal Republic of
LA	German
FA	AB; ABDE
AB	For the parabolic dish solar powerstations of the solar electric generating system (SEGS) type, regenerators are designed which use the thermal oil used for solar collectors as heat carrier. Alternative concepts with concrete and/or phase change material as storage material are compared. The design for a compound regenerator with a capacity of 200 MWhth is discussed. Using quasi steady state thermodynamic process calculations, the interaction between the regenerator and powerstation operation is measured and the use of the store is thus quantified. From annual energy balances, the effect of solar field size and store capacity on the duration of annual powerstation operation is determined. Finally, from an economy calculation, one can prove that the additional investment in an enlarged solar field and a thermal energy store reduces the electricity generating costs of the plant, (orig.)
CC	*140703
CT	CALCULATION METHODS; HEAT STORAGE; OPERATION; REGENERATORS; SIMULATION; SOLAR COLLECTORS; SOLAR POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT *SOLAR POWER PLANTS: *SOLAR COLLECTORS
BT	ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; POWER PLANTS; SOLAR EQUIPMENT; STORAGE

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 4

L4	ANSWER 2 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN	1994(0):99103 ENERGY
TI	Design of a C02-CH4 reformer for a 100 Kw parabolic dish solar concentrator.
AU	Steinfeld, A.; Segal, A.; Levy, M. (Weizmann Inst. of Science, Rehovoth (Israel))
CS	Weizmann Inst. of Science, Rehovoth (Israel) (6860000)
NC	90-05 25/90-1-85
NR	INIS-mf-13968
SO	Jan 1991. 6 p. OSTI as DE94628358; NTIS (US Sales Only); INIS.
DT	Report; Progress Report
CY	Israel
LA	English
FA	AB
AB	Design of a C02-CH4 reformer. A schematic diagram of the system components is shown. (authors). 1 fig.
CC	*140300; F1522
CT	CARBON DIOXIDE; CATALYTIC CONVERTERS; CHEMICAL REACTION KINETICS; CHEMICAL REACTION YIELD; COMPUTER CODES; COMPUTERIZED SIMULATION; DESIGN; PARABOLIC DISH COLLECTORS; PROGRESS REPORT; SOLAR ENERGY CONVERSION; SPECIFICATIONS; THERMOCHEMICAL HEAT STORAGE -PARABOLIC DISH COLLECTORS: *THERMOCHEMICAL HEAT STORAGE; *THERMOCHEMICAL HEAT STORAGE: *CATALYTIC CONVERTERS; *THERMOCHEMICAL HEAT STORAGE: *COMPUTERIZED SIMULATION CARBON COMPOUNDS; CARBON OXIDES; CHALCOGENIDES; CONCENTRATING COLLECTORS; CONVERSION; DOCUMENT TYPES; ENERGY CONVERSION; ENERGY STORAGE; EQUIPMENT; HEAT STORAGE; KINETICS; OXIDES; OXYGEN COMPOUNDS; PARABOLIC COLLECTORS; POLLUTION CONTROL EQUIPMENT; REACTION KINETICS; SIMULATION; SOLAR COLLECTORS; SOLAR EQUIPMENT; STORAGE; YIELDS
ET	C*H*0; C02; C cp; cp; 0 cp; CH4; H cp; C02-CH4

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PLANTS; STORAGE; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 9

L4	ANSWER 7 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN	1986(1):1691 ENERGY
TI	Design of a 13 MWe parabolic trough plant at Daggett. California.
AU	Kroizer, 1. (Luz Engineering, Encino, CA) [United States]
CS	Solar Energy Research Inst, Golden, CO (USA) (9506687)
NR	SERI/SP—271-2664; CONF-8406111—; DE85002949
SO	Design and performance of large solar thermal collector arrays. Mar 1985. pp. 534-536 Availability: NTIS, PC A24/MF A01; 1. Conference: International Energy Agency workshop on the design and performance of large solar thermal collectors, San Diego, CA, USA, 11 Jun 1984
DT	Report Article; Conference
CY	United States
LA	English
DN	ERA-11:005107
AB	The solar power plant design characteristics and system description at Daggett California are presented. The solar collector assembly (SCA) is the primary building block of this modular system. A single SCA consists of a row of eight parabolic trough collectors, a single drive motor, and a local microprocessor control unit. The basic components of the parabolic trough collector are a mirrored glass reflector, a unique and high-efficiency heat collection element, and a positioning system. The heat collection element includes a stainless steel absorber tube coated with a black chrome selective surface, which is contained within a unique and high-efficiency evacuated cylindrical glass envelope. The SCA is designed to have an operating efficiency of 67% at 265 deg C under a direct normal insolation of 3500 kJ/m2. The operation of the system is discussed.
CC	*140700
CT	*SOLAR THERMAL POWER PLANTS: -OPERATION; *SOLAR THERMAL POWER PLANTS: -PERFORMANCE; PARABOLIC TROUGH COLLECTORS; POWER GENERATION; SENSIBLE HEAT STORAGE
BT	CONCENTRATING COLLECTORS; ENERGY STORAGE; EQUIPMENT; HEAT STORAGE; PARABOLIC COLLECTORS; POWER PLANTS; SOLAR COLLECTORS; SOLAR EQUIPMENT; SOLAR POWER

SOLAR EQUIPMENT; SOLAR POWER PLANTS; SOLAR REFLECTORS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 12

L4 ANSWER 10 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1985(7):44992 ENERGY
TI Performance characteristics of solar thermal power generation system with flat plate mirror and parabolic mirror.
AU Chinen, M.; Anzai, S.; Sasaki. S.; Sato, S.; Sumida, 1.; Taki. T.; Tsukamoto, M. (Energy Research Laboratory, Hitachi Ltd., Hitachi) [Japan]
NR CONF-830839-
SO Solar world congress. Vol. 3.
Szokolay, S.V.
Oxford, England: Pergamon Press. 1983. pp. 1581-1585
Conference: Solar world congress, Perth, Australia, 15 Aug 1983
DT Book Article; Conference
CY United Kingdom
LA English
AB The IMWe solar thermal power generation pilot plant featuring plane-parabolic type concentrators and molten salt heat storages succeeded to generate IMWe power and operated about 2 years. Thermal simulation of the plant predicted the plant operation well and confirmed designed performance of the heat storage system. Optical performance of concentrator was evaluated and led to the following results. 1. The optical performance of the evaporator was satisfactory, and the measured error of parabolic mirror and collecting pipe bending had negligible effect on evaporator concentrator. 2. The banding of collecting pipe produced slight leakage in superheater concentrator, that is about 3%. 3. Adjustment were needed to some sun tracking mechanism due to the friction in sliding parts of it after about 2 years operation.
CC *140700; 141000
CT *SOLAR THERMAL POWER PLANTS: *MIRRORS; *SOLAR THERMAL POWER PLANTS: *PARABOLIC REFLECTORS; *PARABOLIC REFLECTORS: -PERFORMANCE; *SOLAR THERMAL POWER PLANTS: -PERFORMANCE; -MIRRORS: -PERFORMANCE; COMPUTERIZED SIMULATION; OPTICAL PROPERTIES; POWER RANGE 1-10 MW
BT EQUIPMENT; PHYSICAL PROPERTIES; POWER PLANTS; SIMULATION; SOLAR CONCENTRATORS;

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ENERGY FILE SEARCH RESULTS - P310399K 26 NOV 1999 15:02:41 PAGE 17

ANSWER 14 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
1982(17):122788 ENERGY
Comparison of electrochemical and thermal storage for hybrid parabolic dish solar power plants.
Steele, HL.; Wen, L. (JPL, Pasadena, Calif, USA) [United States]
Am. Soc. Mech. Eng., [Pap.] (1981) (81-WA/Sol-27) vp
CODEN: ASMSA4
Journal
United States
English
ERA-07:049782
The cost of storage systems which can compete with the use of fuel in hybrid parabolic dish solar power plants is identified for one set of specific assumptions. The hybrid plants burn fuel to increase the hours of usage each day. The cost and performance characteristics of concentrators, receivers and power conversion units are based on estimates by the contractors developing this hardware under the direction of the Department of Energy and the Jet Propulsion Laboratory (JPL). Thermal storage systems are not yet designed and only the cost goal which would make them competitive is known. 12 refs.
«140703; 142000; 250904; 141000
•DISTRIBUTED COLLECTOR POWER PLANTS: -ENERGY STORAGE; -DISTRIBUTED COLLECTOR POWER PLANTS: *HEAT STORAGE; -DISTRIBUTED COLLECTOR POWER PLANTS: -PARABOLIC DISH COLLECTORS; COST; ELECTRIC BATTERIES; HYBRID SYSTEMS; PERFORMANCE; POWER RANGE 1-10 MW; VERY HIGH TEMPERATURE
CONCENTRATING COLLECTORS; ELECTROCHEMICAL CELLS; ENERGY STORAGE; EQUIPMENT; PARABOLIC COLLECTORS; POWER PLANTS; SOLAR COLLECTORS; SOLAR EQUIPMENT; SOLAR POWER PLANTS; SOLAR THERMAL POWER PLANTS; STORAGE; THERMAL POWER

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 18

L4	ANSWER 15 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN	1982(17):122775 ENERGY
TI	Parabolic trough development: lessons learned at Willard and Gila Bend.
AU	Dugan, V.L. (Sandia National Labs., Albuquerque, NM) [United States]
NR	CONF-801203-; DE81015033
SO	National conference on renewable energy technologies. 1980. pp. 6.3-6.4 Availability: NTIS, PC A99/MF A01.
DT	Conference: National conference on renewable energy technologies, Honolulu, HI, USA, 7 Dec 1980
CY	Report Article; Conference
LA	United States
DN	English
	ERA-07:049745
AB	Two irrigation projects, one at Willard, New Mexico, and the other at Gila Bend, Arizona, are briefly described, and lessons learned from three years of operating experience relative to collectors, energy transport, engines, and thermocline storage are outlined. (LEW)
CC	*140703
CT	*PARABOLIC TROUGH COLLECTORS: -IRRIGATION; ARIZONA; NEW MEXICO; RANKINE CYCLE ENGINES; SENSIBLE HEAT STORAGE; SOLAR HEAT ENGINES
BT	CONCENTRATING COLLECTORS; ENERGY STORAGE; ENGINES; EQUIPMENT; FEDERAL REGION IX; FEDERAL REGION VI; HEAT ENGINES; HEAT STORAGE; NORTH AMERICA; PARABOLIC COLLECTORS; SOLAR COLLECTORS; SOLAR EQUIPMENT; STORAGE; USA

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ENTEC FILE SEARCH RESULTS - P327382K 24 NOV 1999 01:02:02 PAGE 25

L3 ANSWER 22 OF 39 ENTEC COPYRIGHT 1999 FIZ Karlsruhe
AN 1995:0116924 ENTEC
TI Regeneratoren mit Beton und Phasenwechselmaterial als Speichermasse.
Regenerators with concrete and phase change material as storage mass.
AU Ratzesberger, R.; Hahne, E.; Beine, B.
SO Energiespeicher fuer Strom, Waerme und Kaelte.
Energy storage for electric power, heat and refrigeration.
Verein Deutscher Ingenieure (VDI) - Gesellschaft Energietechnik, Duesseldorf (DE)
Duesseldorf: VDI-Verl. 1994. p. 467-481. of 481 p.
Serientitel: VDI-Berichte. v. 1168.
Konferenz: VDI-GET conference: Electric power and thermal energy storage for electric power, heat and refrigeration, VDI-GET-Tagung: Energiespeicher fuer Strom, Waerme und Kaelte, Leipzig (DE), 6-7 Dec 1994
ISBN: 3-18-091168-9
DT Kapitel der Monographie; Konferenz
CY Deutschland, Bundesrepublik
LA Deutsch
FA AB; ABDE
IP FIZ Karlsruhe
ABDE Die Firma Siempelkamp, Krefeld, hat in einem BmFT-Vorhaben einen Regenerator mit temperaturbestaendigem Beton als Speichermaterial entwickelt. Als Waermetraeger dient das synthetische Thermooel aus dem Solarfeldkreislauf mit 400 C und einem Betriebsdruck von 16 bar. Dieser Beton-Regenerator wurde von Dinter F. (1992) in einer umfassenden technischen und oekonomischen Berechnung als das guenstigste Speicherkonzept fuer die bestehenden Parabolrinnen-Solarkraftwerke ermittelt. Am ZSW wurden im Rahmen des BmFT-Vorhaben zwei Testmodule mit zusammen 50 kWh_Leistungsaufnahme eingehend untersucht. (orig./HW)

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RESPONSES TO COMMENT LETTER #8
(Public Solar Power Coalition - January 30, 2015)

Comment Letter #8 was hand-delivered to SCAQMD staff in the form of a poor image quality photocopy of handwritten materials with reference materials attached. Because this comment letter contains several patches that are either difficult to decipher or are illegible, wherever the difficulty occurs, SCAQMD staff has attempted to either summarize or transcribe the text to assist the reader with understanding the nature of the comment and the context of the responses provided.

8-1 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"Solar Energy is BARCT and should have been submitted as the Best Available Retrofit Technology [illegible] with the backup options cited by staff but solar thermal system with line focus concentrator within 100 miles of the District supplying 354 MW (Megawatts) have been operating for 30 to 20 years. See Power Point printout 9 pages on SEGS solar energy electric generating systems (9 in all – 1x14 MW, 6x30 MW, and 280 MW). These have been the largest operation solar thermal at moderate temperature 500 - 700 °F and higher temps can be operated for use with point double axis solar [illegible] of 1000 °F +++ plus storage. (9 see the 9 page power point print out provided by PSPC/HE."*

SCAQMD staff is aware of the types of solar technologies available and their capabilities. Companies may choose to make use of solar technologies to provide heat and/or power for their facilities. However, for existing and new fuel-fired equipment, the SCAQMD regulates combustion sources through several SCAQMD Regulations (e.g., Regulations IX, X, XI, XIII, and XIV). While solar energy has merits for providing an alternative source of energy on a smaller scale (e.g., residential or commercial applications) or at the utility level, solar energy has not been identified as a feasible replacement source of energy to fulfill the extensive electrical demand and reliability needs of individual, heavy industrial facilities in the NOx RECLAIM program.

In addition, the reference materials linked to this comment as "Attachment A" (e.g., "An Overview of the Kramer Junction SEGS Recent Performance" and the National Renewable Energy Laboratory report "Survey of Thermal Storage for Parabolic Trough Power Plants") do not provide evidence to support the suggestion that solar energy be considered BARCT for any specific source category involved in this rule amendment.

8-2 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"PSPC/HE should be hired as [a] consultant to show the solar options [from] both solar thermal and P.V photovoltaics and hybrids as soon as possible. This can form the center of on, near and further solar thermal SCHP, combines solar combined heating and cooling. District heating and cooling system (absorption vis a vis Dr. Bercum etc. as well as electricity). The repair of sewage and water systems will be*

planned at the same time as well as replacing old nat[ural] gas system a la San Bruno explosion in PG&E territory [illegible].

BARCT is a "technology forcing" control measure cite 2012 California Supreme Court Decision on VOC in American Coatings Association vs. SCAQMD. The law is clear and as pointed out in the current litigation [illegible] the commenter has with the District (with a Draft Amended [illegible] and now federal EPA etc. You can pay now for the construction at a lower costs [sic] or pay more later. A recent study by the [illegible] Economic Advisory says and demonstrated that climate change implementation will cost 40 percent+ each 10 years that we wait."

With regard to the suggestion that the commenter should be hired as a consultant, the commenter is invited to submit a proposal to the SCAQMD Technology Advancement Office with a description of the proposed project, budget and proposed deliverables. In addition, the commenter should periodically review the requests for proposals from the SCAQMD that may be of interest and submit proposals accordingly.

With regard to the remark that BARCT is a technology forcing control measure, see Response 8-1 for why the SCAQMD believes that solar energy, while a very beneficial alternative energy source that we support, does not qualify as BARCT.

8-3 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

"The SEGS plants were brought to the SCP decades by the [illegible]/consultant. This information was [illegible] between early 1991 AQMP Draft and the final adopted in mid year July 1991. Our litigation followed but without a follow through – the time to act is now if not yesterday."

The commenter has not provided a correlation that explains how the SEGS plants and the 1991 AQMP are linked to the currently proposed amendments to the NOx RECLAIM program. As such, SCAQMD staff is unable and not required to prepare a response to this comment.

8-4 This comment requests a full Environmental Impact Report (EIR) to be prepared for the proposed project.

The SCAQMD is not required to prepare an EIR for the proposed project, but is required to prepare a full environmental analysis and has done so. Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an EIR once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD operates pursuant to a regulatory program that was certified by the Secretary of the Resources Agency on March 1, 1989 in accordance with CEQA Guidelines §15251 (l) and as codified in SCAQMD Rule 110 - Rule Adoption Procedures to Assure Protection and Enhancement of the Environment. Thus, in accordance with the SCAQMD's certified regulatory program, a Program Environmental Assessment (PEA) has been prepared for the proposed project. The PEA is a substitute CEQA document that has been prepared in lieu of an EIR as allowed by

CEQA Guidelines §15252. Nonetheless, the PEA provides the same quality of analysis and will afford the public the same amount of time for comment and review on the Draft PEA as would be provided for under a Draft EIR (e.g., 45 days).

8-5 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"In reference to the December 5, 2014 document, at least solar energy must be studied as an alternative. The areas covered are energy, GHG green house [sic] gases, transportation and traffic as well as water (even the fact that over 20 percent of the District's state energy is used to move water.)"*

As explained in Response 8-1, SCAQMD does not believe that solar energy qualifies as BARCT for sources involved in this rule amendment. (Utilities are already required to source 33 percent of their power from renewable sources, including solar energy, by 2020.) While solar energy has merits for providing an alternative source of energy on a smaller scale (e.g., residential or commercial applications) or at the utility level, solar energy has not been identified as a feasible replacement source of energy to fulfill the extensive electrical demand and reliability needs of individual, heavy industrial facilities in the NOx RECLAIM program. Further, in accordance with CEQA Guidelines §15126.6, the Draft PEA shall describe a range of reasonable alternatives to the project which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives. However, the Draft PEA is not required to consider alternatives which are infeasible. For these reasons, solar energy as "BARCT" for all sources was not considered as an alternative in the Draft PEA.

8-6 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"Immediate total solar conversion means now or yester year. Climate change etc. was addressed in the 1992 BC cases that are in the record in the Superior and Appeals Courts in the state as well as the Federal 9th Circuit Appeal Court. This time with a plethora of environmental and community groups joining us HE/PSPC in litigation. The drought continues."*

There are no substantive remarks on the currently proposed amendments to the NOx RECLAIM program or the associated CEQA document in the legible portions of this comment. As such, SCAQMD staff is unable and not required to prepare a response to this comment.

8-7 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"The fact that almost two years ago the District had all of the information in hand prior litigation with us from the sunshot initial draft incorporated by reference herein as well as the complete sections of solar thermal and solar photovoltaic technology. Sunshot is a play on words for Kennedy's moon shot in the 1960's. Over 60 percent*

on it [sic] was for air grip parity as of last year with only 40 percent of this passing. This is for everywhere in the U.S.A. All other [illegible] in SC119641 Eder vs. SCAQMD as well as B251627 [illegible] as the Federal Record and Federal Register September 3, 2014 and all information submitted to date as well as in the future are incorporated here into the record."

Of the legible words, the sentences and phrasing structure do not raise, in the context presented, any substantive remarks on CEQA or on the NOP/IS. In addition, the attachments to Comment Letter #8, "An Overview of the Kramer Junction SEGS Recent Performance" and the National Renewable Energy Laboratory report "Survey of Thermal Storage for Parabolic Trough Power Plants" also do not correlate to the text in this comment. As such, SCAQMD staff is unable and not required to prepare a response to this comment.

8-8 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

"At the January 7 GB meeting, Eder/PSIC stated that (as is part of the record [sic]) no consultant was hired to study solar energy as BARCT which has been before the District and CARB for decades!"

Because the comment does not specify the year when the January 7th Governing Board (GB) meeting occurred, it is unclear if the commentator meant to say the January 9, 2015 GB meeting, or the January 7, 2011 GB meeting. These are the only two recent GB meetings that fell on January 7. In any event, for both of these GB meetings, the minutes do not mention the topic of solar energy or BARCT. The following is the link to the minutes for the January 9, 2015 GB meeting: http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-feb6-001.pdf?sfvrsn=2. The following is the link to the minutes for the January 9, 2015 GB meeting: http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2011/2011-feb4-001.pdf?sfvrsn=2. In addition, the comment does not mention any source category for which solar energy would be BARCT.

With regard to the suggestion that the SCAQMD should hire a solar energy consultant, see Response 8-2.

8-9 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

"As the cover article in this week's Economist says carpe diem of sieze [sic] the day. Gov. Brown set 50 percent solar renewables by 2030 of [illegible] but his off by 100 percent in February and 100 percent/50 percent [illegible] by EPA for 2023!"

Of the legible words, the sentences and phrasing structure do not raise, in the context presented, any substantive remarks on CEQA or on the NOP/IS. As such, SCAQMD staff is unable and not required to prepare a response to this "CEQA" comment.

APPENDIX H (OF THE DRAFT PEA)

CEQA SCOPING MEETING COMMENTS AND RESPONSES TO COMMENTS

INTRODUCTION

The NOP/IS for the proposed project was circulated for a 57-day public review and comment period, which started on December 5, 2014, and ended on January 30, 2015. During this public comment and review period, the SCAQMD held a CEQA Scoping Meeting at the SCAQMD's headquarters on January 8, 2015. The CEQA Scoping Meeting was held in accordance with the requirements in Public Resources Code §21083.9 (a)(2) for any project that may have statewide, regional or areawide significance.

CEQA SCOPING MEETING COMMENTS AND RESPONSES TO COMMENTS

At the CEQA Scoping Meeting, oral public testimony was received relative to the rule development process and the CEQA process. The following is a summary of the CEQA-specific comments that were made at this meeting and the responses to the comments.

1. Comment: Since SCR technology is being considered for BARCT, there could be an increase in the need to transport, store and use ammonia as part of operating SCR equipment. The Draft PEA should contain an analysis of ammonia.

   Response: As explained in the NOP/IS, both SCR and SNCR technologies utilize ammonia, a toxic air contaminant (TAC) and acutely hazardous material. Because hazard and hazardous materials impacts could occur as a result of the increased use, transport and storage of ammonia as well as the potential for an accidental release of ammonia into the environment, the NOP/IS identified ammonia as a source of potentially significant hazards and hazardous materials impacts and these impacts were analyzed in the Draft PEA.

2. Comment: A different approach to tackling the NOx RECLAIM RTC shave via an "incremental BARCT analysis shave" is currently being developed by industry groups and will be submitted to SCAQMD as a recommendation for consideration as part of the rule development process. As such, the Draft PEA should include and analyze the potential environmental impacts of the "incremental BARCT analysis shave" as one of the alternatives.

   Response: A Draft PEA is being prepared for the proposed project and several alternatives to the proposed project will be analyzed in accordance with the requirements in CEQA Guidelines §15126.6. The purpose of analyzing alternatives is to find project components that minimize impacts while still attaining the project's objectives. Alternatives were developed by altering specific components of the proposed project. One of the alternatives analyzed in the Draft PEA is an alternative based on the industry proposal.

3. Comment: The CEQA Scoping presentation states that all equipment subject to the proposed BARCT will install the most cost-effective control technology to meet proposed reductions. Does this mean that the CEQA document will analyze the environmental impacts of installing SCR technology now, even if SCR technology was not installed as a result of the NOx RTC shave in 2005?

Response: The Draft PEA analyzes a wide assortment of cost-effective BARCT options, including SCR technology. The analysis in the Draft PEA examines the potential environmental impacts of installing SCR technology in response to the currently proposed project, regardless of whether SCRs were installed in response to the previous NOx RTC shave that was implemented in 2005.

4. Comment: In addition to analyzing an alternative comprised of the industry's proposed "incremental BARCT analysis shave," the Draft PEA should also analyze an alternative that focuses on meeting the minimum NOx emission reduction goals in the 2012 AQMP per Control Measure #CMB-01 (e.g., at least three to five tons per day of NOx reductions by 2023).

Response: As required per CEQA Guidelines §15126.6 (e), the Draft PEA contains a "No Project" alternative that analyzes what would reasonably be expected to occur in the foreseeable future in the event the proposed project is not approved. A specific alternative limited to three to five tons per day of NOx RTC reductions was not analyzed because its impacts would likely fall between those resulting from the industry proposal (Alternative 3) and the No Project alternative (Alternative 4). The Draft PEA thus provides a range of potential impacts for these alternatives.

5. Comment: While the proposed revisions to the semi-annual assessment procedures in protocols for Rule 2011 and Rule 2012 will cause affected facilities difficulties to implement, it is not clear whether these proposed revisions would cause an adverse environmental effect.

Response: SCAQMD staff invites the commentator to provide more specific information regarding the implementation difficulties. Even if there are implementation difficulties, SCAQMD believes that the proposed revisions to the semi-annual assessment procedures are administrative in nature and as such, no physical environmental effects requiring a CEQA evaluation would be expected from implementing this portion of the proposed project.

APPENDIX I

COMMENT LETTERS RECEIVED ON THE DRAFT PEA AND RESPONSES TO COMMENTS

INTRODUCTION

A Draft Program Environmental Assessment (PEA) was released for a 53-day public review and comment period from August 14, 2015 to October 6, 2015 which identified the environmental topics of aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic, as potentially being significantly adversely affected by the project. The SCAQMD received eight comment letters regarding the analysis in the Draft PEA during the public comment period.

The comment letters have been numbered (see Table I-1 below) and individual comments within each letter have been bracketed and numbered. Following each comment letter is SCAQMD staff's responses to the individual comments.

Table I-1
List of Comment Letters Received Relative to the Draft PEA

Comment Letter	Commenter
#1	Latham & Watkins on behalf of the Regulatory Flexibility Group
#2	Alston & Bird LLP on behalf of the Western States Petroleum Association
#3	Charles F. Timms, Jr. on behalf of the City of Burbank Department of Water and Power
#4	Los Angeles Department of Water and Power
#5	Phillips 66 Company
#6	Curtis L. Coleman on behalf of the NOx RECLAIM Industry Coalition
#7	Natural Resources Defense Council et al.
#8	Communities for a Better Environment

Comment Letter #1

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Hong Kong	Shanghai
Houston	Silicon Valley
London	Singapore
Los Angeles	Tokyo
Madrid	Washington, D.C.

File No. 018282-0000

October 6, 2015

VIA E-MAIL

Barbara Radlein
bradlein@aqmd.gov
Program Supervisor, CEQA Special Projects
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: **DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDMENTS TO REGULATION XX**

Dear Ms. Radlein:

On behalf of the Regulatory Flexibility Group (RFG), we are submitting the following comments on the Draft Program Environmental Assessment (Draft PEA) prepared to support the proposed amendments to South Coast Air Quality Management District (SCAQMD) Regulation XX- NOx RECLAIM. These comments are limited to the legal adequacy of one of the alternatives analyzed in Chapter 5 of the Draft PEA (Alternative 3 – Industry Approach). The RFG also endorses the comments submitted on behalf of the NOx RECLAIM Industry Coalition and the Western States Petroleum Association. 1-1

During its presentation at the September 23, 2015 Special Stationary Source Committee meeting, SCAQMD staff expressed the view that the industry proposal to reduce current NOx RECLAIM allocations by 8.79[1] tons per day (tpd) fails to meet minimum legal requirements because it fails to attain "maximum reductions achievable," as required by California Health & Safety Code § 40406, and is not equivalent to levels that would be achieved under command and control. 1-2

[1] The industry proposal is to reduce allocations by the level of emission reduction determined to be achievable through deployment of 2015 best available retrofit control technology (BARCT). This level of emission reductions is referred to herein as "BARCT-equivalent emission reductions." 8.79 tpd is the SCAQMD staff's calculated BARCT-equivalent emission reductions. Industry believes that if certain necessary corrections were made to the staff's analysis, the actual figure would be 6.6 tpd. For the purposes of this discussion, we will assume that the staff's figure is correct.

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LATHAM&WATKINS LLP

SCAQMD staff is correct that Health & Safety Code § 40440(b)(1) requires adoption of rules and regulations that "require the use of . . . best available retrofit control technology for existing sources." Best available retrofit control technology (BARCT) is defined in Health & Safety Code § 40406 as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." 1-3

Having determined that BARCT-equivalent emission reductions equate to 8.79 tpd, the SCAQMD staff must adopt amendments to the RECLAIM program necessary to achieve that level of reductions in order to meet the legal requirements identified above. Assuming that there is no dispute that 8.79 tpd is the correct level of BARCT-equivalent emission reductions (see footnote 1), then there is no dispute that achieving this level of emission reductions will satisfy applicable legal requirements. 1-4

By applying what it refers to as its "remaining emissions methodology," staff has concluded that it is necessary to reduce allocations by 14 tpd in order to achieve the desired 8.79 tpd in emission reductions. In other words, the reduction in allocations must be 63% higher than the desired reduction in emissions in order to achieve the desired reductions. According to staff, a reduction in allocations of anything less than 14 tpd will not achieve the minimum required emission reductions, and therefore will not satisfy applicable legal requirements. It is on this basis that the staff concludes that the industry proposal to reduce allocations by 8.79 tpd fails to satisfy minimum legal requirements. Thus, staff's legal critique of the industry proposal is entirely dependent on the premise that one must reduce allocations by 14 tpd in order to achieve 8.79 tpd in emission reductions. 1-5

The problem with the staff's analysis, is that there is nothing to support the underlying premise that 14 tpd in allocations must be eliminated in order to achieve 8.79 tpd in emission reductions. In fact, the SCAQMD's own historical data indicate that a much more modest reduction in allocations would achieve the desired emission reductions. The SCAQMD previously adopted amendments to achieve BARCT equivalency in 2005. In that case, allocations were reduced from 34.2 tpd to 26.5 tpd between 2005 and 2011, a reduction of 7.7 tpd. Over that same period of time, emissions were reduced from 26.4 tpd to 20 tpd, a reduction of 6.4 tpd. What this past experience demonstrates is that for every tpd that allocations are reduced, 0.83 tpd of emission reductions will occur. Put another way, the level of reduction in allocations should be no more than 17% higher than the desired level of emission reductions. 1-6

Thus, past experience indicates that the reduction in allocations necessary to achieve 8.79 tpd in emission reductions is 10.3 tpd (17% higher than the desired reductions); not 14 tpd (63% higher than the desired reductions). The drastic reduction in allocations proposed by SCAQMD staff will require overall reductions of greater than 8.79 tpd in order to bring actual emissions in line with remaining allocations. Thus, RECLAIM sources will be required to achieve emission reductions that are greater than what the SCAQMD staff has determined to be BARCT. In other words, RECLAIM sources will be required to achieve reductions above and beyond the BARCT levels that would be required under a command and control regime. 1-7

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LATHAM & WATKINS LLP

Not cited by the staff in is presentation, but also relevant to this discussion is Health & Safety Code § 39616. Health & Safety Code § 39616(c)(1) requires that a market-based incentive program adopted in lieu of command and control regulations "result in an equivalent or greater reduction in emissions at equivalent or less cost compared with . . . measures that would have otherwise been adopted [command and control] . . ." (emphasis added). Similarly, Health & Safety Code § 39616(c)(7) requires that the market based program "not result in disproportionate impacts measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources . . ." 1-8

By requiring emission reductions in excess of what has been determined to be achievable with BARCT, the SCAQMD staff proposal imposes costs on RECLAIM sources that are greater than those that would be imposed under a command and control regime, and imposes disproportionate impacts on RECLAIM sources relative to other stationary sources, in violation of Health & Safety Code § 39616. Thus, it is the SCAQMD staff proposal that runs afoul of applicable legal requirements; not the industry proposal. 1-9

During the September 29, 2015 Public Consultation Meeting on the proposed amendments, SCAQMD staff indicated that it had been suggested that Health & Safety Code § 39616(c) did not apply to the proposed action of the Governing Board to amend the RECLAIM program. Section 39616(c) provides as follows:

> (c) In adopting rules and regulations to implement a market-based incentive program, a district board shall, at the time that the rules and regulations are adopted, make express findings, and shall, at the time that the rules and regulations are submitted to the state board, submit appropriate information, to substantiate the basis for making the findings that each of the following conditions is met on an overall districtwide basis:

Presumably, the party suggesting that this section does not apply to the proposed amendments is focusing on the phrases "at the time that the rules and regulations are adopted" and "at the time that the rules and regulations are submitted to the state board" and arguing that the findings specified later in the section need only be made upon initial adoption of the program and not upon its subsequent amendment. Such an interpretation is nonsensical. First, amendments to rules and regulations are "adopted" by the Governing Board and "submitted to the state board" in the same manner as initial adoption. Second, the specified findings go to the implementation of the program and were clearly intended to survive and apply beyond the date that the rules are adopted and submitted to the California Air Resources Board. Under the proffered interpretation, the Governing Board could make the required findings and adopt the program one day, and then amend it the next with complete disregard for the findings. Clearly, the legislature did not intend to create the possibility of such an absurd outcome. The only reasonable interpretation is that Health & Safety Code § 39616(c) applies to the proposed action of the Governing Board and the specified findings must be made. 1-10

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For the reasons set forth above, Alternative 3 analyzed in the Draft PEA, or any other alternative designed to achieve the necessary BARCT-equivalent emission reductions, would meet applicable legal requirements. 1-10 Con't

Best regards,

Michael J. Carroll
of LATHAM & WATKINS LLP

cc: Robert A. Wyman
Regulatory Flexibility Group

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RESPONSES TO COMMENT LETTER #1
(Latham & Watkins on behalf of the Regulatory Flexibility Group – October 6, 2015)

1-1 This comment begins by introducing the parties represented by the letter; no response to this part of the comment is necessary. Relative to comment about the adequacy of Alternative 3 in the Draft PEA, see Responses 1-2 through 1-10. Relative to the comment expressing support for two letters submitted by the Western States Petroleum Association and the NOx RECLAIM Industry Coalition, which are referred to herein as Comment Letter #2 and Comment Letter #6, respectively, see Responses to Comment Letters #2 and #6.

1-2 The comment states that staff's presentation at the September 23, 2015 Special Stationary Source Committee Meeting expressed that the industry proposal fails to meet legal requirements and is not equivalent to levels that would be achieved under command-and-control. Staff continues to stand by that statement as further explained in the following responses to this letter. This issue is also raised in Comment Letter #2. See Responses 2-33, 2-34 and 2-35.

1-3 The comment acknowledges staff's determination that Health and Safety Code §40440 (b)(1) requires the use of BARCT, as defined, for existing sources.

1-4 The comment states that the BARCT-equivalent emission reductions of 8.79 tons per day meet the legal requirements in the Health and Safety Code. Staff disagrees that this amount is the level of reductions necessary to meet the legal requirements for the RECLAIM program. Based on staff's analysis, a reduction of 14 tpd of NOx RTCs is needed to induce actual emission reductions equivalent to BARCT. The 2015 BARCT analysis demonstrated that there would be an actual NOx emission reduction of 8.77 tpd from the 2011-2012 activity levels at 2015 BARCT compared to the same activity levels at 2005 BARCT. This represents 8.77 tpd of NOx reductions in actual emissions. If the overall NOx RTC holdings had closely matched the total amount of actual NOx emissions from the NOx universe, the removal of 8.77 tpd of NOx RTCs would likely induce an equivalent amount of actual NOx emission reductions. However, over the past five years, actual NOx emissions from RECLAIM facilities fell below the overall NOx RTC holdings by 21-30%, resulting in approximately 5.45-8.41 tpd of unused NOx RTCs (unused for compliance purposes). In addition, if the years 2007-2011 are considered (implementation of the 2005 NOx shave), RTCs were reduced by 7.66 tpd, while emissions were reduced only 4.09 tpd, for a ratio of 0.53 ton of emissions reduced for every ton of RTCs reduced. The Draft PEA accounted for the fact that if RTCs are not significantly reduced, there will be enough excess RTCs in the market that facilities can simply surrender unused RTCs, without making significant real emission reductions. Therefore, the removal of 8.77 tpd of NOx RTCs would initially eliminate some, if not all, of these excess NOx RTCs from the market and only thereafter would result in actual emissions reductions. As a result, RTC reductions of 8.77 tpd would be less than the BARCT-equivalent level of actual NOx emission reductions.

1-5 The comment makes reference to the remaining emissions methodology that staff used which concludes that it is necessary to reduce allocations by 14 tpd in order to achieve the desired 8.77 tpd in emission reductions and that anything less than a 14 tpd reduction would not meet the applicable legal requirements. Staff agrees with this statement and the reasons are explained in Response 1-4.

1-6 The comment states that there is nothing to support the premise that 14 tpd must be removed from the RECLAIM program in order to achieve 8.79 tpd in emission reductions. The commenter makes reference to the 2005 amendments which reduced allocations by 7.7 tpd, while emissions were reduced by 6.4 tpd. This comment also suggests that between 2005 and 2011, a comparison of 0.83 tpd emission reductions to 1 tpd RTC reductions would result in a ratio of 0.83 such that the level of reduced allocations should be no more than 17 % higher than the desired level of emission reductions.

Staff disagrees with the commenter's claim for the reasons previously explained in Response 1-4. Also, staff acknowledges that the previous RECLAIM amendment resulted in an allocation reduction of 7.7 tpd from 2007 to 2011, but the emission reductions in that same time frame actually amounted to 4.1 tpd. Also, it is important to note that a large portion (almost two thirds) of these reductions were actually due to shutdowns, so the staff proposal must remove more RTCs from the market to achieve the required amount of emission reductions.

To examine past shaves to determine the ratio between the amount shaved and the amount of actual emission reductions that occurred from the RECLAIM universe (presumably to derive an alternative shave amount) is a flawed approach because there is no fixed ratio between actual emissions reductions and RTCs shaved. Between 2005 and 2011, a comparison of 0.83 tpd emission reductions to 1 tpd RTC reductions would result in a ratio of 0.83, but that included only two years (2005 - 2006) worth of data when there were actual emission reductions, but no RTC shave. If the analysis looks at the actual shave years (2007 through 2011), the ratio would actually be a comparison between 4.09 tpd reductions to 7.66 tpd RTCs reduced, or 0.53 instead of 0.83. Moreover, if there were a larger amount of available unneeded RTCs, such as the 73 percent projected to occur with the Industry Approach (or even more if the Industry Approach used the 6.6 tpd target) it is likely that facilities would not significantly reduce actual emissions but would simply surrender unneeded RTCs. Thus, no fixed ratio can be determined to allow the suggested alternative approach.

1-7 The commenter claims that the level of reduction of allocations should be 17% higher than the desired emission reductions, which would result in a 10.3 tpd shave instead of a 14 tpd shave, and that the staff proposal would require reductions greater than what staff has determined as BARCT.

Staff disagrees with the commenter's claim. As explained in Responses 1-4 and 1-6, a large portion of the reductions from the previous amendments to the NOx RECLAIM program were the result of shutdowns and not from the installation of BARCT. Also, as explained in Response 1-4, the staff proposal would achieve the BARCT reductions necessary to meet the applicable legal requirements.

1-8 The comment refers to Health and Safety Code §39616, which states that a market program will result in equivalent or greater emission reductions at equivalent or less cost than command-and-control and that the program would not result in disproportionate impacts. The comment states that staff has not cited this section and feels that it is relevant.

Although staff is not legally required to make the findings in accordance with Health and Safety Code §39616 because the proposed project consists of an amendment to existing rules, staff has demonstrated that the findings could be made anyway. With the exception of the 2000-2001 period when the California energy crisis took place, the historical discrete NOx RTC prices ($5,500 or lower per ton) have consistently been at the lower end of or below the cost- effectiveness range of pollution controls. As a result, many RECLAIM facilities have accrued substantial cost-savings over the years by being able to delay or forego the installation of pollution control equipment that would have been required at different points in time by command-and-control regulations. Further, if findings need to be made in accordance with Health and Safety Code §39616 (c)(1) for the currently proposed shave alone, the proposed shave is expected to only reduce the future stream of this cost-savings. Even so, a reduced cost-saving is still a cost-savings when compared to command-and-control regulations. Thus, the currently proposed amendments to the NOx RECLAIM program will clearly not cost more than the projected costs that would occur under command-and-control.

1-9 The comment claims that the staff proposal does not meet the legal requirements of Health and Safety Code §39616 because it imposes costs on RECLAIM sources that are greater than those that would be imposed under a command-and-control regime.

Staff disagrees with this claim and refers the commenter to the Response 1-8 as well as the Socioeconomic Report. Staff has never considered the “cost” of the shaved RTCs to be recognized as a “cost” for determining equivalency with command-and-control. At the outset of the RECLAIM program in 1993, RTCs were allocated to RECLAIM facilities free of charge, yet they now have value to the facilities as a commodity that can be bought and sold. While RTCs have value, they are not a property right. The currently proposed amendments to the RECLAIM program will reduce the number of RTCs. Since there was no cost associated with allocated RTCs for a facility, the proposed reduction of RTCs would not create a financial loss to the RECLAIM universe. Any additional purchase of RTCs executed by a facility is made in lieu of controlling emissions. The choice between purchasing RTCs and installing or modifying air pollution control equipment or making other changes to reduce emissions is solely a business decision that is made to generate an expected stream of cost-savings afforded only by the RECLAIM program; this choice is not available to facilities under command-and-control. Therefore, any RTC investment loss should not be considered as a compliance cost to be compared to the compliance cost under command-and-control regulations. Moreover, this loss may be offset by any potential increase in RTC price due to a decreased RTC supply, which would subsequently raise the market value of a facility's remaining RTC holdings. Finally, any loss of "value" of shaved RTCs cannot be compared to command-and-control, because in that case, there would be no RTCs and thus, no similar "value" would be created. Staff acknowledges that, for a portion of the smaller emitters that have no identified cost-effective ways to control emissions further, these smaller emitters may have been affected by past RTC price spikes and could potentially be impacted by future price fluctuations, either due to their RTC holdings or their limited financial capacity to hedge against price volatilities. However, their potential losses incurred as buyers would be concurrent economic gains for the RTC sellers; therefore, the resulting net cost, if any, is expected to be zero or negligible to the entire RECLAIM program, particularly when compared with the program's cost savings. While individual facilities may experience different costs or savings depending on whether they are a buyer or seller, Health and Safety Code §39616 applies to the RECLAIM universe as a whole. Finally, the regulatory history pertaining to Health and Safety Code §39616 is explained in the Socioeconomic Report (see pp. 4-6).

1-10 The commenter expresses disagreement with staff's position that the requirements in Health and Safety Code §39616 do not apply because the findings need to be made at the time of program adoption and not for an amendment. The commenter also states that the industry proposal would achieve the necessary BARCT-equivalent reductions and would meet the applicable legal requirements

Health and Safety Code §39616 does not require a BARCT assessment. As explained in Responses 1-8 and 1-9, analyses were conducted anyway that demonstrate the findings of Health and Safety Code §39616 could be made. Staff believes that the proposal to shave 14 tpd of allocations would achieve the necessary BARCT-equivalent reductions and would meet the applicable legal requirements.

Comment Letter #2

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VIA ELECTRONIC & FIRST CLASS MAIL

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South Coast Air Quality Management District
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Re: Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market

Dear Ms. Radlein:

We respectfully submit, on behalf of the Western States Petroleum Association ("WSPA") and its members, these comments on the draft Program Environmental Assessment ("PEA") for Proposed Amended Regulation XX – Regional Clean Air Incentives Market ("RECLAIM"). WSPA is a non-profit trade association that represents oil and gas exploration, production, refining and marketing companies, some of whom own and operate facilities in the RECLAIM program. 2-1

The draft PEA suffers from fundamental problems that undermine the entire environmental analysis. The draft PEA purports to consider a project to implement the Air Quality Management Plan ("AQMP") and to evaluate best available retrofit control technology ("BARCT"), but narrowly focuses on construction activities associated with the replacement NOx emissions control equipment for selected facilities to achieve 14 tons per day ("TPD") in NOx reductions. Further, the construction activities that are evaluated in the draft PEA have not been confirmed by the District's independent expert, resulting in a proposed project that is likely infeasible. The District's improper focus on 14 TPD in NOx reductions is particularly apparent in the alternatives analyses where the majority of the alternatives require 14 TPD or more of NOx reductions – a skewed selection of alternatives which fails to meet the "reasonable range of alternatives" requirement. Aside from these fundamental problems, the draft PEA lacks adequate analysis in several individual resource areas. 2-2

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Attachment 1 to this letter provides more detailed comments on this draft PEA from WSPA's technical consultant, and are hereby incorporated by reference. ("Attachment 1"). 2-3

WSPA has previously submitted numerous comments on the proposed regulation itself, as well as the notice of preparation and initial study ("NOP/IS") for the draft PEA, but these comments have received insufficient attention from the District in its environmental analyses.[1] The District responds to the NOP/IS Letter by claiming that technical analyses have been considered, when an in-depth evaluation of the industry's technical concerns has not been performed. 2-4

WSPA has serious concerns with both the proposed rule amendments and the draft PEA, and believe that the requirements under the California Environmental Quality Act ("CEQA") have not been satisfied. Furthermore, both the proposed amendments and the draft PEA must be revised and recirculated to address the comments raised by WSPA and the numerous other commenters in order to correct errors, disclose all significant impacts, and allow the consideration of feasible mitigation measures or project alternatives to reduce or avoid these impacts. 2-5

I. Fundamental Problems With The Draft PEA Undermine The Environmental Analysis

Under CEQA, an EIR is an informational document designed to provide public agencies and the public with detailed information about the impacts that a proposed project is likely to have on the environment, analyze the ways in which the significant effects of a project might be minimized, and identify alternatives to the project.[2] The District's draft PEA, as a substitute EIR under its certified regulatory program, is also subject to the substantive provisions of CEQA.[3] 2-6

Fundamental flaws in the draft PEA's project description and objectives, the scope of review, and the selection and analysis of alternatives, pervade the document, ultimately resulting in a misleading document in specific resource areas as well. Many of the errors in the draft PEA are related to problems with the methodology, assumptions,

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[1] See, in particular, the letter submitted by WSPA dated August 21, 2015 on the preliminary draft staff report ("PDSR") and Attachments 1 and 2 (hereinafter referred to as "WSPA's August 21 Letter"). See also the January 30, 2015 letter submitted by WSPA as part of the Industry RECLAIM Coalition commenting on the NOP/IS (the "NOP/IS Letter"), and WSPA's May 27, 2015 letter on the April 29, 2015 SCAQMD NOx RECLAIM Working Group Meeting. For convenience, these letters are provided as Attachments 2, 3 and 4 to this letter.

[2] Pub. Resources Code §§21002, 21002.1(a), 21061; 14 Cal. Code Regs. §15362; see also Pub. Resources Code §§21100, 21150.

[3] 14 Cal. Code Regs. §15250; *City of Morgan Hill v. Bay Area Air Quality Management District*, 118 Cal.App.4th 861, 874-875 (2004).

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which WSPA described in detail in its August 21 Letter and which are reiterated here as they also relate to inadequacies under CEQA. WSPA believes that the draft PEA must be revised and recirculated for further public review and comment, all in compliance with CEQA. 2-6 Con't

A. The Project Description is Flawed, Misleading and Hinders Analysis

"An accurate, stable and finite project description is the *sine qua non* of an informative and legally sufficient EIR."[4] An accurate project description is an essential requirement because an EIR must be "prepared with a sufficient degree of analysis to provide decisionmakers with information which enables them to make a decision which intelligently takes account of environmental consequences."[5] If the project description contains inaccurate or misleading information, the entire analysis may be tainted. "A curtailed, enigmatic or unstable project description draws a red herring across the path of public input."[6] 2-7

1. The project description includes amendments to Regulation XX, but the draft PEA evaluates only environmental effects of BARCT construction activities

The proposed project is described as "amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements and to modify the RECLAIM trading credit (RTC) 'shaving' methodology."[7] However, the draft PEA examines only the construction activities that purportedly achieve a reduction of 14 TPD of NOx emissions, and fails to evaluate in any manner the potential environmental effects of effectively eliminating the NOx RTC market.

The RECLAIM program is a cap and trade program, and it is misleading for the District to characterize the proposed severe changes to this program as merely a series of construction projects to achieve BARCT requirements. Depending on how they are implemented, changes to the marketplace can have wide-ranging impacts that are not limited to BARCT construction, but also to the operation of the RECLAIM facilities subject to the District's proposed severe shave. The District's focus on NOx emissions reduction – and the PEA's correspondingly limited analysis – has resulted in foreseeable consequences that are neither considered in the District's rulemaking nor analyzed in its environmental assessment in the form of the draft PEA. 2-8

[4] *County of Inyo v. City of Los Angeles*, 71 Cal.App.3d 185, 192 (1977).

[5] *Dry Creek Citizens Coalition v County of Tulare*, 70 Cal.App.4th 20, 26 (1999).

[6] *Inyo*, 71 Cal.App.3d at 197-198.

[7] Draft PEA, p. 1-1.

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While the District certainly has the authority to prepare a CEQA document solely for BARCT requirements, and if that is the District's intention with the draft PEA, then the draft PEA needs to clearly state that intention in the project description. "[I]ncessant shifts among different project descriptions" undermines the CEQA process "as a vehicle for public participation."[8] However, the project description purports to include an RTC "shave," and the CEQA document needs to evaluate it. For this reason alone, the draft PEA must be revised and recirculated for further public review and comment. 2-8 Con't

2. The draft PEA does not substantiate the fundamental assumptions that form the basis of the BARCT construction activities

As explained above, the draft PEA improperly focuses solely on BARCT construction activities for its analysis, but the viability of those construction activities being adequately represented and analyzed in the draft PEA cannot be substantiated, creating further uncertainty for the project description. "An EIR may not define a purpose for a project and then remove from consideration those matters necessary to the assessment of whether the purpose can be achieved."[9] Given that the District has narrowly defined the purpose of the project as implementing BARCT, it still must be able to substantiate that those BARCT construction activities can actually be performed. 2-9

The District erroneously assumes all its proposed BARCT requirements are not only technologically feasible but can be achieved unilaterally despite evidence suggesting the proposed BARCT levels may not be cost effective or feasible for all RECLAIM facilities subject to the District's proposed severe shave. As WSPA has explained previously, most recently in its August 21 Letter, this is not the case. In November 2014, Norton Engineering Consultants ("NEC"), the third party expert hired by the District to "ground truth" the District's technical analysis in this rulemaking, presented findings in its BARCT Feasibility and Analysis Review.[10] However, when the preliminary draft staff report for the proposed amendments was released on July 21, 2015, it was apparent that many of NEC's findings were ignored, misunderstood, or misstated by the District. As described in WSPA's August 21 Letter, failure to correct some of the assumptions and errors in the staff report for this rulemaking skews the analysis for nearly 40 operating units (i.e., RECLAIM NOx sources). 2-10

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[8] *Inyo,* 71 Cal.App.3d at 197.

[9] *County of Inyo v. City of Los Angeles,* 124 Cal.App.3d 1, 7-9 (1981).

[10] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014, http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-refinery_112614.pdf?sfvrsn=2 (last accessed September 13, 2015).

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Moreover, there is no support for the District's assumption that certain NOx sources subject to this rulemaking can achieve 2 ppm NOx levels using new or upgrade selective catalytic reduction systems ("SCR"). This 2 ppm NOx level assumption is an integral component of the District's calculus justifying the currently proposed severe shave. While CEQA provides that disagreements among experts does not make an EIR inadequate, that is not the case here with the draft PEA.[11] As a threshold matter, the District cannot claim to be an expert in specific applications unique to the refining and petrochemical industry; indeed that is apparently the reason for its hiring of an outside third party expert to verify (i.e., "ground truth") the District's technical assumptions. Importantly, the District has been presented with a highly technical analysis from its own third party expert on the ability – or inability – of certain types of NOx sources to achieve 2 ppm NOx levels using SCR, and effectively dismissed this information in favor of unsubstantiated assertions that certain equipment can, indeed, meet such NOx levels and reductions.[12] 2-11

The District also assumes that the installation of the BARCT can and will be implemented in the specified timeframe, which is fairly aggressive. This aggressive time frame is unrealistic and again, has not been substantiated. A number of internal and external factors influence when a company can and will undertake a construction project. WSPA members report that completion of all needed projects to implement the proposed NOx reductions would likely require at least eight (8) years. (Attachment 1, p. 13).[13] It is also a possibility that, depending on the economic climate and incentives, a project would not be implemented at all. In the current economic climate for the oil and gas industry, a more realistic schedule is required for an adequate CEQA review. 2-12

The draft PEA also purports to conduct a site-specific analysis for certain resource areas, but makes unsubstantiated conclusions to eliminate further environmental analysis. For example, the PEA determines noise impacts will not occur from the project because any increase in noise levels will be within the thresholds of the industrial facilities. The PEA makes similar extrapolations from a site specific review of the aesthetics, taking a specific example of a facility where a wet gas scrubber ("WGS") had been installed, resulting in a characteristic steam plume. The PEA essentially states that because these refineries are in industrial areas, additional WGS plumes would not have an aesthetic impact.[14] The PEA's assumptions and extrapolations make an informed analysis difficult. 2-13

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[11] See, e.g., *Karlson v. City of Camarillo*, 100 Cal.App.3d 789, 805 (1980).

[12] See letter from NEC to the District dated August 10, 2015, and included as Attachment 2 to WSPA's August 21 Letter, attached to this letter as Attachment 2.

[13] WSPA also recommended that the shave implementation schedule be "back-loaded" to accommodate a longer, more realistic project implementation period with at least 2 of the proposed 4 TPD (currently being proposed for 2016) being moved to 2019 or later. WSPA's August 21 Letter, p. 3, attached to this letter as Attachment 2.

[14] Draft PEA, p. 4.1-4.

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The draft PEA should identify realistic assumptions based on facts to properly evaluate potential environmental effects of construction activities, and a one-size fits all approach that dismisses the potential for environmental effects based on the industrial locations of the facilities is not sufficient. 2-14

In short, the PEA makes unsubstantiated industry-wide generalizations in determining that technology is feasible, implementation timeframes are reasonable, the site specific impacts will be negligible, and the individual businesses will perform as expected. These generalizations cannot support the PEA's assumptions, particularly in light of the District's own third party expert's efforts to correct the errors in its technical analysis. If an EIR is "so fundamentally and basically inadequate and conclusory in nature" that public comment on the draft is essentially meaningless, or if significant new information is added to an EIR, it must be recirculated for further public review.[15] The PEA should be revised to substantiate its assumptions and reevaluate its conclusions accordingly, and should then be recirculated for further public review and comment. 2-15

B. The PEA Purports To Be A Program-Level Document, But Construction Activities Generally Require Project-Level Review

The draft PEA is described as a "program CEQA document" ostensibly because it consists of proposed amendments to Regulation XX.[16] As noted above, however, the draft PEA appears to evaluate BARCT construction activities, and specific construction projects generally require a project-level analysis. This distinction is important because a program-level review can be more abbreviated and the District apparently seeks to utilize that approach, but it has now embarked on a partial project-level review of BARCT construction activities. As noted above, noise is dismissed in the PEA and not evaluated at all, even though noise is an environmental topic commonly reviewed in a project level EIR for a construction project. If the District seeks to transform a rule-making into a construction project, it needs to do so in compliance with CEQA. 2-16

Furthermore, the draft PEA, which is a "substitute CEQA document" pursuant to the District's certified regulatory program, states that the "program" CEQA document may be used by other agencies for "future related actions." Section 15253 of the CEQA Guidelines addresses use of a substitute CEQA document by responsible agencies, and the District should clarify how the provisions of that Section have been satisfied. 2-17

The draft PEA's insufficient project level analysis for BARCT construction activities reinforces WSPA's main critique of the District's proposed amendments to Regulation XX—the technical analysis to support the proposed amendments is 2-18

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[15] *Laurel Heights Improvement Ass'n v Regents of Univ. of Cal.*, 6 Cal.4th 1112 (1993); 14 Cal. Code Regs. §15088.5(a).

[16] Draft PEA, p. 1-3.

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inadequate.[17] If these construction activities had been properly evaluated in the CEQA document at a project level, the infeasibility of the proposed BARCT would have become apparent. 2-18 Con't

C. The PEA Overlooks Impacts From the "Whole Of The Project"

An EIR must consider the whole of an action.[18] "Project" means the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and that is an activity directly undertaken by any public agency.[19] An "indirect physical change" may be one resulting from any economic and social effects of a project, and that change too must be evaluated.[20] The CEQA Guidelines provide: "Where a physical change is caused by economic or social effects of a project, the physical change may be regarded as a significant effect in the same manner as any other physical change resulting from the project."[21] While not all projects evaluated under CEQA have sufficient economic and social effects to warrant further analysis regarding consequential physical effects, this project is unique in that it consists of amendments to a market system – economic consequences are integral to RECLAIM operations. 2-19

1. The Draft PEA fails to consider the physical effects resulting from reasonably foreseeable economic and social effects

The draft PEA summarily asserts: "No indirect or indirect physical changes resulting from economic or social effects have been identified as a result of implementing the proposed project."[22] No citation is provided for this conclusion, and no analysis was performed to support this conclusion. As a result and the clear fact that the draft PEA proposes such a severe RTC "shave" that it could potentially eliminate the NOx RTC market, an analysis must be performed to evaluate the potential physical changes that might result from the reasonably foreseeable economic and social effects of the project. 2-20

[17] *See also* WSPA's August 21 Letter.

[18] Because the District has adopted a Certified Regulatory Program under California Public Resources Code §21080.5, an environmental assessment ("EA") may be prepared instead of an EIR or negative declaration. An EA is the equivalent of an EIR under the Certified Regulatory Program.

[19] Cal. Code Regs. § 15378(a)(1).

[20] CEQA Guidelines Section 15131. See, e.g., *Bakersfield Citizens for Local Control v. City of Bakersfield*, 124 Cal.App.4th 1184 (2004) (holding that CEQA requires consideration of social or economic impacts if they may lead to adverse changes in the physical environment such as "urban decay").

[21] 14 Cal. Code Regs. §15064(e).

[22] Draft PEA, p. 1-16.

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More specifically, the draft PEA fails to consider the physical impacts of an analysis in which the economic consequences of the rule result in reasonably foreseeable changes in the regulated sectors. The District is well aware of the statistic it cites in its staff report and PEA: since the start of the RECLAIM program, the number of facilities in the program has shrunk by approximately 30 percent.[23] Where there were once 392 RECLAIM facilities in the South Coast Air Basin, there are now only 276. While the District cites this statistic, it makes no effort to analyze or consider the significance of it, or to examine the physical changes in the environment that resulted in the PEA. 2-21

This reduction in RECLAIM facilities means that some productivity within the Basin has been lost, and the draft PEA should evaluate the potential for future loss of productivity from sources within the RECLAIM system, particularly those RECLAIM facilities subject to the District's proposed severe shave. This analysis in the PEA should evaluate the Basin's energy needs and assess whether there would be adequate sources of reliable power if the proposed project were to result in lowered productivity within RECLAIM facilities and the businesses that support and supply these facilities. It should also consider whether lowered production of the affected products could result in adverse environmental impacts within or outside of the Basin. It should consider the environmental impacts of leakage, which is a well-known, and thus, foreseeable consequence of sub-regional cap and trade schemes. CEQA provides that "[a]ny emissions or discharges that would have a significant effect on the environment in this state" are subject to CEQA.[24] Accordingly, the District is obligated to analyze whether potential changes in operations resulting from the imposition of this aggressive RTC shave would result in potential environmental impacts, including increased emissions due to needing to source products from outside the South Coast Air Basin where the RECLAIM program applies. 2-22

The District's incomplete and selective approach neglects to consider potential environmental impacts beyond the narrow scope of construction associated with installation of the anticipated BARCT required by the proposed project. In the District's own words, RECLAIM is a market-based program which was "designed to use the power 2-23

[23] Draft PEA, p. 2-2.

[24] Cal. Pub. Resources Code § 21080. In certain instances, the mandate of CEQA to ensure a high level of environmental protection extended to considering out of state activities as part of the project due to resulting in-state impacts. (See 58 Ops. Cal. Atty. Gen. 614 (1975), opining that where California cities were joining forces with Utah cities to construct a coal plant in Utah that would provide power to California, and related transmission lines would have to be built from Utah into California, any project-related EIRs had to examine the environmental consequences of the project as a whole. Additionally, because the project area spanned multiple states, local California agencies were required to look at the impacts of the project as a whole.)

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of the marketplace" to reduce air emissions from stationary sources.[25] A proposed shave effectively manipulates that marketplace. It stands to reason that an aggressive, deep manipulation – like the one proposed by the District – will impact RECLAIM facilities differently than one that is less drastic. The District is proposing a massive change in the marketplace designed to change behavior and cause reactions, yet the District assumes that the only reaction will be small scale construction projects involving installation of NOx control equipment to meet shave requirements. The District is proposing a massive change that will cause RECLAIM facilities and the businesses that support and supply these facilities to *react* in ways that are reasonably foreseeable by the District. These reactions, in turn, will have environmental impacts, which should have been analyzed in the PEA. 2-23 Con't

The RECLAIM program was introduced as an alternative to traditional command and control requirements, and was intended to provide business within the South Coast Air Basin with greater flexibility and financial incentive to reduce air pollution. As set forth in WSPA's August 21 Letter, the District has accomplished the substantial NOx emissions reductions achieved to date by reducing RTCs across the board. With the present project, not only is the District proposing deep cuts to the remaining RTCs, but it is imposing these cuts in a targeted, uneven manner. This is a significant manipulation of the marketplace, with foreseeable consequences that the PEA has neglected to analyze. The likely impacts resulting from the District's chosen methodology occur in various resource areas, as described further in this letter. However, by not recognizing the market-driven business considerations, the PEA has neglected to analyze and disclose the "whole of the project," in violation of CEQA. 2-24

CEQA prohibits segmenting a project into separate actions in order to: avoid environmental review of the "whole of the action"[26]; defer environmental analysis; ignore the foreseeable environmental impacts of the end result of a project; or, avoid considering potential cumulative impacts. Thus, a lead agency may not limit environmental disclosure by ignoring other activities that will ultimately result from approval of a particular project. The District's limited focus on technical equipment related to control of NOx emission reductions to achieve the severe RTC shave, to the exclusion of other foreseeable impacts is evidence of the District's failure to consider the entire project and its potential environmental impacts. 2-25

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[25] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim (last accessed September 12, 2015).

[26] Cal. Pub. Resources Code § 21065.

2. The draft socioeconomic report is deficient, and a revised report should be prepared and recirculated concurrently with a revised draft PEA

The draft Socioeconomic Report for the RECLAIM amendments provides little assistance in evaluating this issue as it considers only a limited number of potential economic and social issues, based solely on BARCT construction activities, and does not delve into the potential for physical effects resulting from the severe RTC "shave." WSPA will be submitting comments on the draft Socioeconomic Report, and once those comments have been considered and addressed, the draft PEA should be revised and recirculated for public review and comment to reflect the District's analysis of the potential environmental effects of any physical changes resulting from these economic and social effects. 2-26

Furthermore, the Draft Socioeconomic Report was only circulated on September 7, 2015 – weeks after the completion of the PEA. Failure to consider socioeconomic impacts in conjunction with the environmental review hampers the environmental review of the whole of the project. A proper socioeconomic analysis should have been completed in advance of, or at minimum in conjunction with, the draft PEA, and the draft PEA should have analyzed the resulting physical changes based on the socioeconomic effects of the RECLAIM amendments.

For example, the socioeconomic analysis with respect to the BARCT cost effectiveness could well have environmental impacts which were not adequately analyzed in the PEA. Health and Safety Code §39616 requires RECLAIM to achieve emissions reductions "at equivalent or less cost" than otherwise applicable command and control regulations. The project proposes cost effectiveness of $50,000/ton threshold, above which the District assumes, for purposes of CEQA analysis, that a facility would decline to install the given air pollution control technology. However, as discussed in greater detail below, this $50,000 is more than twice the AQMD's cost effectiveness threshold for command-and-control programs. The socioeconomic impacts of adopting new BARCT threshold, and setting such a high cost effectiveness figure, could result in operational changes which have physical impacts on the environment. In order to comply with CEQA, the PEA must analyze the foreseeable impacts of this component of the project. 2-27

D. The Project Objectives Are Disconnected From The Project Evaluated In The Draft PEA 2-28

An EIR is required to have a "statement of objectives sought by the proposed project."[27] The statement of objectives should include the underlying purpose of the project, and it should be clearly written to guide the selection of alternatives to be

[27] 14 Cal. Code Regs. §15124(b).

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evaluated in the EIR.[28] Here, however, the objectives do not appear to inform the alternatives; instead, they appear to be independent of the proposed project. In fact, the Alternatives section of the draft PEA contains little analysis of whether the project objectives can be satisfied because they have become irrelevant, thereby infecting the Alternative analysis in its entirety (as discussed below). 2-28 Con't

The draft PEA appears instead to apply an unstated objective – reduce NOx RTCs by 14 TPD or more – which actually creates inconsistencies with the District's own plans and with the Health & Safety Code provisions with which it purports to comply. The District's 2012 Air Quality Management Plan ("AQMP") included NOx reduction control measure CMB-01. This control measure provided that additional reductions of NOx RTCs in the range of 3 to 5 tons per day ("TPD") would occur. The PEA states that one of the project objectives is to "[a]chieve the proposed NOx emission reduction commitments" of CMB-01. Yet the current project's proposal to reduce NOx RTCs by 14 TPD goes far beyond the control measure's initial recommendation of 3 to 5 TPD target. 2-29

WSPA and the Industry RECLAIM Coalition commented on this issue in their NOP/IS Letter. The District's response is that the current project "is the result of a much more rigorous and in-depth analysis as compared to the analysis that supported control measure CMB-01."[29] However, it is apparent that the analysis conducted by the District focused primarily on assessing the maximum number of remaining NOx emissions that could be reduced, to the exclusion of other analyses. As described above, the proposed project has the potential to trigger unintended consequences that were not considered in the draft PEA. The new, aggressive reduction in NOx RTCs, combined with the ambitious timeframe and questionable assumptions about facility performance suggest that the District did not undertake the same holistic view of the RECLAIM program and market as it did when it adopted the 2012 AQMP. Again, it appears that in its zeal to reduce NOx emissions by as much as possible, the District has ignored the potential repercussions of such a severe reduction. 2-30

Another unstated, but unsubstantiated, objective is the establishment of a $50,000/ton cost effectiveness threshold that justifies its severe shave. However, this is inconsistent with the stated District's objective: to "[c]omply with the requirements in Health and Safety Code …§39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT."[30] Compliance with that provision of the Health and Safety Code requires that the market-based emissions program should result in (1) emissions reductions equivalent to or greater than reductions that would have resulted under command and control, **and** (2) "***at equivalent or less cost*** 2-31

[28] 14 Cal. Code Regs. §15124(b).

[29] Draft PEA, p. 1-15.

[30] Draft PEA, p. 2-4.

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compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment."[31] The currently proposed emissions reductions may well provide greater reductions of NOx than would occur under traditional command and control regulation. However, this comes at a cost which far exceeds what implementation of BARCT would cost under command and control.

More specifically, the project proposes a $50,000/ton cost effectiveness threshold, above which the District assumes, for purposes of a CEQA analysis, a facility would decline to install a given NOx air pollution control technology to meet the severe shave requirements.[32] However, this $50,000 is more than twice the District's cost effectiveness threshold for command-and-control programs. As WSPA explains in its August 21 Letter, the 2012 AQMP used a cost threshold for NOx control measures of $22,500 per ton.[33] As another point of reference, the District's current Best Available Control Technology ("BACT") guidance document presents a discounted cash flow ("DCF") cost effectiveness threshold of only $19,100 per ton.[34] 2-31 Con't

The District, in its preliminary draft staff report for the NOx shave rulemaking, has also made misleading cost analysis assumptions which have the effect of making the overall costs for the severe shave look lower than actual. For example, in its staff report, the District proposed a 25-year Useful Life when calculating equipment cost effectiveness. This is misleading because the District rulemaking – which is often technology forcing – occurs on a more frequent basis. For example, the District last amended the NOx RECLAIM rules only 10 years ago. As WSPA explains in its August 21 Letter, assuming a 25-year project life dilutes the capital cost over a longer period of time than what the company is likely to actually realize. 2-32

As discussed below, Alternative 3 (the Industry Approach) meets project objectives, with fewer impacts. Thus, the project, as currently proposed, does not meet CEQA's requirements, and the PEA must be revised and recirculated for public review and comment. 2-33

[31] Cal. Health & Saf. Code § 39616(c)(1), emphasis added.

[32] Draft PEA, p. 4.2-7.

[33] SCQAMD, 2012 AQMP, December 2012, pp. 4-43.

[34] SCAQMD, BACT Guidelines, Part C: Policy and Procedures for Non-Major Polluting Facilities, 2006.

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E. The Alternatives Analysis Is Flawed

1. The analysis of alternatives is inadequate to allow for informed comparison

The alternatives analysis is critical to the integrity of an EIR.[35] Under CEQA, an EIR must describe a reasonable range of alternatives to the proposed project, or to its location, that would feasibly attain most of the project's basic objectives while reducing or avoiding any of its significant effects, and must evaluate the comparative merits of those alternatives.[36] The alternatives analysis has been described as "the core of an EIR."[37]

An EIR's analysis of alternatives and mitigation measures must focus on those alternatives with the potential to avoid or lessen a project's significant environmental effects.[38] The alternatives discussed in an EIR should be ones that offer substantial environmental advantages over the proposed project.[39]

Here, the PEA evaluates 5 alternatives, and except for the Alternative 4 (No Project) and Alternative 3 (Industry Approach), all other alternatives propose 14 TPD or more of NOx emission reductions. Given that the proposed project has remaining significant environmental effects with the proposed project at 14 TPD, the failure to include any additional alternatives other than Alternative 3 (Industry Approach) at a lesser reduction of NOx emissions does not satisfy CEQA's requirement for a "reasonable range of alternatives." Furthermore, CEQA generally prohibits a selection of "straw man" alternatives which are intended to be knocked down in favor of the proposed project.[40] The majority of the alternatives require 14 TPD or more of NOx reductions, including an alternative for 15.87 TPD, suggesting that the District's selection of alternatives was guided not by the ability to reduce environmental effects, but by an effort to support the proposed project. 2-34

[35] *In re Bay Delta Programmatic Evtl. Impact Report Coordinated Proceedings*, 43 Cal.4th 1143, 1162 (2008) ["The EIR is the heart of CEQA, and the mitigation and alternatives discussion forms the core of the EIR."]

[36] 14 Cal. Code Regs. §15126.6(a).

[37] *Citizens of Goleta Valley v Board of Supervisors*, 52 Cal.3d 553, 564 (1990).

[38] Pub. Resources Code §21002; 14 Cal. Code Regs. §15126.6(a)-(b).

[39] *Citizens of Goleta Valley v. Board of Supervisors, supra*, 52 Cal.3d at 566.

[40] *Sierra Club v. Contra Costa County*, 10 Cal.App.4th 1212, 1217 (1992).

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2. Alternative 3 is the environmentally superior alternative

The PEA's alternatives analysis is flawed because it appears to reject alternatives based solely on the total TPD of emissions reduced, rather than a more comprehensive analysis that evaluates the remaining significant effects associated with the proposed project. The CEQA Guidelines provide that "the discussion of alternatives shall focus on alternatives to the project or its location which are capable of avoiding or substantially lessening any significant effects of the project, even if these alternatives would impede to some degree the attainment of the project objectives,…"[41] Alternative 3 achieves the project objectives and is the environmentally superior alternative. As such, the District should adopt Alternative 3 rather than the proposed project.

Here, the District has chosen, as the proposed project, to employ a methodology that has significantly greater potential environmental impacts than Alternative 3. Specifically, the District proposes that NOx RTC holdings for major refineries be "shaved" by 67 percent; NOx RTC holdings for non-major refineries and other facilities among the top 90 percent of RTC holders be shaved by 47 percent. This aggressive "shaving" method would remove nearly all of the unused NOx RTCs from the RECLAIM market, ostensibly to reduce NOx emissions from RECLAIM facilities. However, the PEA suffers from a narrow view of the RECLAIM universe: by focusing almost exclusively on potential benefits from NOx emissions, the District fails to analyze the environmental impacts that such a drastic NOx RTC reduction is likely to have. 2-35

On the other hand, the Industry Approach (Alternative 3) to NOx reduction would take a more measured and holistic approach, resulting in fewer environmental impacts while still achieving a reduction in NOx emissions. More specifically, the Industry Approach proposes to reduce the unused RTCs in an amount equivalent to those reductions that could be directly attributable to an appropriate and valid BARCT.[42] The Industry Approach would result in an across the board reduction of 33 percent of the unused NOx RTCs – a significant reduction of RTCs and advancement of BARCT – without many of the environmental impacts resulting from the District's methodology.

The draft PEA downplays that Scenario 3 (Industry Alternative) will require less operational use of ammonia, by claiming that it is "not quantifiable."[43] However, no evidence is provided to support that conclusion. In the alternatives air quality analysis, the District asserts that if Alternative 3 were implemented, it would be too difficult to 2-36

[41] 14 Cal. Code Regs. § 1526.6(a).

[42] The Industry Approach is described in section 5.3.2.4 of the draft PEA, as well as in the January 30, 2015 letter to the District regarding the NOP/IS, submitted by WSPA and the other members of the Industry RECLAIM Coalition.

[43] Draft PEA, Table 1-4.

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predict the number of facilities that would install NOx control equipment.[44] First, the District should have acknowledged the unpredictability of facilities implementing the proposed project, which is more aggressive and could trigger correspondingly more drastic business reactions. Instead, the District assumes there that all facilities will fall in line to install NOx control equipment as it predicts. Second, the likely NOx control equipment installation projects can be quantified. 2-36 Con't

Furthermore, the alternatives analysis in the PEA fails to explain why the proposed project will only reduce NOx emissions 8.72 TPD when history suggests a 1:1 relationship between RTC reductions and program emissions.[45] If the project objective is to meet BARCT at 8.7 TPD, Alternative 3 meets that objective with fewer environmental impacts, and thus, should be the environmentally preferred alternative. 2-37

The lead agency has the flexibility to approve an alternative to the proposed project if that alternative better addresses the agency's environmental concerns.[46] An EIR's failure to analyze an adequate range of alternatives deprives the lead agency of the ability to provide this sort of meaningful review and selection. Recirculation of a new draft PEA will be required by CEQA because the current PEA has not considered alternatives that have not been previously adequately analyzed but must be analyzed as part of a reasonable range of alternatives. 2-38

II. Specific Resource Areas Lack Adequate Analysis

A. Energy Reliability Impacts Were Not Considered

The District's proposal will dramatically increase the costs for the facilities it has selected to be regulated and the businesses that support and supply these facilities. The PEA acknowledges that if the BARCT is implemented at these selected facilities, there will be an increase in the amount of energy used both during construction, and more significantly, during operation of the facilities. But the PEA only considered whether there would be sufficient energy when all the facilities installed and implemented the BARCT. Given that 100 facilities have ceased to exist in the District's RECLAIM market since its inception, the District needs to consider not only whether there will be sufficient energy to power the BARCT NOx control equipment, but whether important energy reliability needs of the region and State can be met or whether they will be impacted by the District's proposal. 2-39

[44] Draft PEA, p. 5-15.

[45] See, e.g., Draft PEA, Table 1-4; SCAQMD Annual RECLAIM Audit Report, March 2015.

[46] *Sierra Club v. City of Orange*, 163 Cal.App. 4th 523, 533 (2008).

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There is a complete absence of any analysis of electricity or fuel supply impacts. The potential for outages, interruptions and severe price spikes should be considered and analyzed. Also, the future growth in energy demand should be assessed and the impact of this proposed project on the ability to maintain adequate energy supply. This analysis should consider proposed population growth and growth in use of power-consuming electronics (e.g., hospital diagnostic and treatment tools such as high proton lasers are replacing lower-energy using tools) and growth in electrification and energy use more generally. 2-40

B. Air Quality Impacts Were Not Fully Addressed

1. Direct impacts of new and expanded ammonia sources are not addressed

The PEA notes that the proposed project will increase operational use of ammonia, a toxic air contaminant, by 39.5 TPD.[47] The increase is due to the large number of new and expanded ammonia emissions sources associated primarily with the larger number of SCRs that would be required to be installed to meet the severe NOx shave requirements. However, the PEA does not address the impacts from a program which results in increased ammonia emissions. Additionally, as the District's other documents acknowledge,[48] ammonia is a precursor to PM2.5. Accordingly, the PEA should have analyzed the regional impacts from increased secondary formation of PM2.5. 2-41

Furthermore, the draft PEA's analysis of ammonia slip depends on physical conditions which are explicitly omitted from the project description (e.g., use of Ammonia Slip Catalysts or ASC) despite recommendations by Norton to use ASC.[49] Without the ASC, the ammonia slip could be as great as 20 ppmv, but the draft PEA underestimates the ammonia slip to be 5 ppmv, ostensibly based on permit conditions for new SCRs. However, existing SCRs are not necessarily subject to those permit conditions, and thus, ammonia slip of up to 20 ppmv should be considered in the health risk assessment for ammonia emissions.[50]

[47] Draft PEA, Table 1-4; p. 4.4-9.

[48] See, e.g., Supplement to 24-hour PM2.5 State Implementation Plan for South Coast Air Basin proposed at February 6, 2015 Governing Board meeting, agenda item no. 22 (link: http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-feb6-022.pdf?sfvrsn=2 last accessed on September 16, 2015).

[49] Norton Engineering Consultants, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs, Document No. 14-045-7, July 21, 2015, p. 3; see also Draft PEA, Table 2-3.

[50] Draft PEA, Tables 4.2-18 and 4.2-21.

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2. Cumulative impacts from air emissions are not adequately considered

An EIR must discuss the cumulative impacts of a project when its incremental effects are "cumulatively considerable."[51] Moreover, in the specific context of a programmatic EIR, one of the key purposes of the EIR is to "ensure consideration of cumulative impacts that might be slighted in a case-by-case analysis."[52] Programmatic EIRs play an instrumental role in allowing the lead agency to consider broad policy alternatives and program-wide mitigation measures at an early time when the agency has greater flexibility to deal with basic problems in program implementation, or cumulative impacts.[53] Accordingly, the CEQA Guidelines require lead agencies to explain how implementing the particular requirements in the plan, regulation or program under review "ensure[s] that the project's incremental contribution to the cumulative effect is not cumulatively considerable."[54]

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts."[55] "Cumulatively considerable" impacts are present when "the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects" and activities.[56] A lead agency's threshold findings of significance with regard to cumulative impacts must "be supported by substantial evidence"; and, where found, cumulatively considerable impacts must be adequately mitigated.[57] 2-42

As discussed above, there are indirect air impacts from increased ammonia emissions for SCRs. The District also fails to provide substantial evidence that cumulative impacts from increased ammonia emissions for SCRs (which could number in the dozens at a single refinery) will not result in cumulative health risk impact. The PEA makes the conclusory statements that "[e]ven if multiple SCRs are installed at one refinery facility, the locations of all the stacks would not be situated in the same place within the affected facility's property. As such, even with multiple SCR installations, the acute and chronic hazard indices would not be expected exceed the significance

[51] Pub. Resources Code § 21083(b)(2); CEQA Guidelines § 15130(a).

[52] 14 Cal. Code Regs. § 15168(b)(2).

[53] 14 Cal. Code Regs. § 15168(b)(4).

[54] 14 Cal. Code Regs. § 15064(h)(3).

[55] 14 Cal. Code Regs. § 15355.

[56] Pub. Resources Code § 21083(b)(2); 14 Cal. Code Regs. § 15065(a)(3).

[57] 14 Cal. Code Regs. § 15064.7 (b).

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threshold."[58] However, no evidence is provided to support this assumption, and the draft PEA should base its analysis on a conservative assumption regarding the locations of SCRs, and not dismiss the potential environmental effect by relying on unsupported and result-driven assumptions. 2-42 Con't

Furthermore, the PEA's conclusions with respect to potential cumulative health impacts are contradicted by recent District statements that recognize a potential need to control SCR ammonia slip. In a presentation on August 26, 2015, the District proposes possible "short-term" implementation for such a control.[59] Although CEQA does not require compliance with rule or programs that have not yet been adopted, the PEA should address, in its air quality analysis, the underlying concerns driving the proposed 2016 AQMP control measure. However, the project appears to value NOx RTC reductions above all other concerns, and accordingly the lopsided analysis does not acknowledge the related potential ammonia issues. 2-43

C. Water Supply Impacts Are Not Adequately Mitigated

The EIR "must assume that all phases of the project will eventually be built and will need water, and must analyze, to the extent reasonably possible, the impacts of providing water to the entire proposed project." (*Vineyard Area Citizens for Responsible Growth, Inc. v. City of Rancho Cordova*, 40 Cal.4th 412, 431 (2007).) Also, "the future water supplies identified and analyzed must bear a likelihood of actually proving available; speculative sources and unrealistic allocations ('paper water') are insufficient bases for decision-making under CEQA." (*Id.* at 432.)

The draft PEA acknowledges "significant adverse water demand impacts from hydrotesting" requiring the imposition of mitigation measures.[60] The mitigation measures consist of a requirement to use recycled water "if available" and if not, a declaration from the water purveyor indicating why the recycled water cannot be supplied to the project.[61] The draft PEA summarily states that "the potential increase in potable water use cannot be fully supplied either with all potable water or with a combination of recycled water and potable water, since some potable water may still be required." The draft PEA also states: "[T]here is no absolute guarantee at the time of this writing that future supplies of potable or recycled water will be available to all of the affected facilities." 2-44

[58] Draft PEA, p. 4.2-23.

[59] Draft Potential Control Measures Concepts for 2016 AQMP August 2015, at p. 9 (link: http://www.aqmd.gov/docs/default-source/Agendas/aqmp/advisory7-item5-attachment.pdf?sfvrsn=2, last accessed September 16, 2015).

[60] Draft PEA, p. 4.5-9.

[61] Draft PEA, pp. 4.5-9 – 4.5-10.

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CEQA requires a more in-depth evaluation of the availability and reliability of both potable and recycled water for the project.[62] It is insufficient to conclude that a significant impact for water supply exists without providing a more detailed analysis of the amount of water available, the reliability of such water, all of which has become more important as California is facing one of the most serious droughts in history. While the draft PEA identifies the existence of emergency drought regulations, it does not analyze the effect of these regulations – or of local water restrictions – on the facilities subject to the rule.

A similarly deficient analysis was presented in the draft PEA for the water usage associated with the wet gas scrubbers.[63] In that section, the District states that it cannot confirm or verify the use of recycled water and that "it is not known at this time whether water purveyors would be able to supply potable water for those facilities." CEQA requires an actual analysis of the water availability and reliability, and the inability to verify the use of recycled water means that the use of potable water must be evaluated, including an understanding of whether it is available at all. 2-44 Con't

Furthermore, the draft PEA fails to evaluate any further mitigation measures, other than a commitment to use recycled water, if available. Such mitigation measures are speculative, and may be found to be legally inadequate if they are so undefined that it is impossible to gauge their effectiveness.[64] Feasible – and therefore defensible – mitigation could include provisions in the rule that allow for alternative technologies and additional NOx RTCs in the foreseeable event that water supply is increasingly restricted, and the cost of water increases accordingly.

D. Noise Impacts Should Have Been Analyzed

The NOP/IS for the project determined that noise was among the environmental areas which would not be significantly adversely affected by the project. The PEA, in explaining why noise is not considered, states that the facilities are generally industrial in nature, and any increase in noise levels due to construction and installation of BARCT NOx control equipment would be within acceptable limits for an industrial facility. However, this is an example of the District's programmatic review failing to take into account site-specific conditions which could have an adverse impact. Rather than make generalizations about the facilities and extrapolated that there will be no adverse noise levels, the PEA should have undertaken a more conservative analysis to assess whether noise could, in fact, adversely affect receptors in the vicinity of the facilities, including on 2-45

[62] *California Oak Foundation v. City of Santa Clarita*, 133 Cal.App.4th 1219, 1237 (2005) (EIR requires "forthright discussion of a significant factor that could affect water supplies).

[63] Draft PEA, p. 4.5-12 – 4.5-13.

[64] *Federation of Hillside & Canyon Ass'ns v. City of Los Angeles*, 83 Cal.App.4th 1252, 1260 (2000); *Preserve Wild Santee v. City of Santee*, 201 Cal.App.4th 260 (2012).

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nearby roadways based on the local noise ordinances or requirements. Noise impacts could occur from the use of large construction equipment to construct and install NOx control equipment and increase in construction traffic, which can include large trucks, trailers and cranes. Additionally, there could be an increase in noise impacts associated with the operation of the NOx control equipment and the ammonia delivery trucks. 2-45 Con't

E. Solid And Hazardous Waste Is Not Adequately Considered

The PEA fails to adequately analyze potential impacts of hazardous waste as a result of the project. The significant NOx RTC reductions necessitate a high degree of BARCT NOx control installation, most of which consists of SCR technology. While SCR technology has been used in a wide variety of applications and industries over the decades, it nonetheless is generates a hazardous wastestream in the form of spent catalyst which, in turn, requires potential on site storage and off-site transport and disposal.[65] Section 4.6 of the PEA acknowledges that the hazards exist and acknowledges that the generation of hazardous waste and materials will increase. The PEA should also evaluate the impact on communities near hazardous waste landfills, such as Kettlemen Hills, where the impacts may be greater without any corresponding benefit from the District's proposed action. Also, as discussed earlier, the emissions implications of the increased ammonia from the SCR have been overlooked in the District's PEA. 2-46

F. Growth-Inducing Impacts Analysis Is Flawed

An EIR must describe any growth-inducing impacts of the proposed project.[66] As part of the analysis, the EIR must discuss ways in which the project could directly or indirectly foster economic or population growth,[67] and should also describe growth-accommodating features of the project that may remove obstacles to population growth. An EIR must discuss growth-inducing effects even though those effects will result only indirectly from the project.[68] A discussion on growth-inducing effects should not necessarily make assumptions about whether the growth is beneficial, detrimental, or inconsequential to the environment.[69] The purpose of the EIR is to act as an informational document. 2-47

Here, not only does the draft PEA fail to consider the significance of the shrinking number of RECLAIM facilities (as discussed in Section I.C. of this letter), but the PEA also fails to consider the possibility that the facilities within the RECLAIM universe

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[65] See, e.g., "Alternative Control Techniques Document – NOx Emissions from Process Heaters, (U.S. EPA, September 1993), http://www3.epa.gov/ttn/catc/dir1/procheat.pdf.

[66] Pub. Resources Code §21100(b)(5); 14 Cal. Code Regs. §15126(d).

[67] 14 Cal. Code Regs. §15126.2(d).

[68] *Napa Citizens for Honest Gov't v Napa County Bd. of Supervisors*, 91 Cal.App.4th 342, 368 (2001).

[69] 14 Cal. Code Regs. §15126.2(d).

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could grow. In a footnote, the PEA assigns a "growth factor" to different categories of RECLAIM facilities.[70] No explanation is provided about how that growth factor was derived, nor whether it is current or likely to change. The PEA must consider a scenario which allows for more growth of those industries within the RECLAIM universe, and modify the growth-inducing impacts analysis accordingly.[71] 2-47 Con't

III. Conclusion

The District has a very admirable – but narrow – statutorily defined focus: to promulgate rules and regulations which promote air quality in its jurisdiction. Under CEQA, the District is the lead agency for purposes of its own rulemaking. The District must be able to square its obligations as a lead agency to fully analyze and disclose impacts of its discretionary approvals with the narrow focus required of the District's mission to promote air quality within a specific geographic area. The District has failed to adequately balance those obligations here, which has resulted in a PEA that presents a skewed analysis of the potential benefits and impacts of the proposed rule amendments. The District must address the numerous inadequacies of the draft PEA raised in this comment letter, and then, revise and recirculate the draft PEA for public review and comment in order to meet its mandate under CEQA. 2-48

Sincerely,

Nicki Carlsen
ALSTON & BIRD LLP

NC:dtc
LEGAL02/35874006v4

cc: Sue Gornick,WSPA (w/enclosures)

[70] Draft PEA, p. 2-6.

[71] The Growth Inducement section is in Section 4.8.3 of the draft PEA.

ATTACHMENT 1

ADDITIONAL WSPA COMMENTS ON
DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT (PEA)
FOR NO_X RECLAIM AMENDMENTS

Page/Section	WSPA Comment	
Page 1-1, 3rd paragraph	This paragraph describes the project as "amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements and to modify the RECLAIM trading credit (RTC) "shaving" methodology." [emphasis added] This description is not consistent with the project description contained in the AQMD's Notice of Preparation issued 4 December 2014,[1] nor is the description consistent with Project Description contained in the Initial Study.[2] Specifically, neither the NOP Project Description nor the Initial Study Project Description includes any reference to modifying "the RECLAIM trading credit (RTC) "shaving" methodology" in the description of the project or the project objectives.	2-49
Page 1-1, 4th paragraph	The Draft PEA states that "further analysis of the actual BARCT NOx emission control opportunities for the various equipment/process categories demonstrated that the proposed project could achieve 14 tons per day of NOx emission reductions by 2023 which is much higher than estimates provided in the 2012 AQMP." While this value is certainly much higher than contemplated in the 2012 AQMP, it is also not supported by the AQMD Staff's technical analysis.[3] The Staff's analysis does not support a 14 ton per day (TPD) shave as necessary for BARCT equivalency. Rather, the Preliminary Draft Staff Report (PDSR) very clearly demonstrates that not more than 8.79 TPD of emission reductions from the RECLAIM program can be attributed to BARCT advancement; a conclusion that is later echoed in the Draft PEA.[4] Furthermore, a 14 TPD shave reduction of the RECLAIM market may violate the project objectives under the California Health & Safety Code (H&SC). Contrary to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is absolutely no consideration of the economic impacts which would be incurred by RECLAIM facilities under a 14 TPD market adjustment that goes beyond BARCT.	2-50

[1] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."
[2] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.
[3] AQMD, Preliminary Draft Staff Report (PDSR) for Proposed Amendments to NOx RECLAIM, 21 July 2015.
[4] AQMD, Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Table 1-3.

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	And contrary to H&SC §39616(c)(1), AQMD Staff has failed to demonstrate that the RECLAIM program will result in an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment**. Staff has instead applied a cost effectiveness threshold for this RECLAIM rulemaking of $50,000 per ton of NOx reduction which is more than double the cost threshold used for command-and-control rules within the District (i.e., $22,500 per ton[5]). This higher cost threshold clearly imposes a greater cost on RECLAIM sources than would be incurred under command and control regulations. But the Staff proposal to shave 14 TPD, which goes beyond BARCT, exposes RECLAIM facilities to even greater costs than would have been incurred under a command-and-control program. According the Staff's analysis, BARCT equivalency is not more than 8.79 TPD and even that value is overstated since adjustments are needed to account for the findings of the AQMD's third-party refinery expert (Norton Engineering) would reduce the shave for BARCT equivalency to not more than 7.94 TPD.[6] And contrary to H&SC §39616(c)(7), AQMD has failed to demonstrate that the RECLAIM program as amended will not result in disproportionate impacts, measured on an aggregate basis, to those stationary sources included in the program as compared to other permitted stationary sources in the district's plan for attainment. RECLAIM program sources have already reduced NOx emissions by 69% since 1994, whereas command-and-control stationary sources have only reduced NOx emissions by about 44% during that same period.[7] The BARCT levels being proposed by AQMD Staff represent performance levels that have not been demonstrated as broadly achievable for most of the source categories in question. Furthermore, these performance levels go well beyond the command-and-control standards adopted by AQMD under Regulation XI (i.e., the District's command-and-control program), and are well beyond BARCT determinations made by other major California air agencies administering command-and-control programs (e.g., SJVAPCD, BAAQMD, etc.). The resultant impacts would be disproportionate and that is in conflict with H&SC §39616(c)(7). For these reasons, the Draft PEA must be revised to address inconsistencies between the AQMD Staff's proposal and the project objectives, as well as inconsistencies with the Health & Safety Code.	2-50 Con't
Page 1-2, 1st full paragraph	This paragraph suggests that the proposed project will be limited to specific types of equipment/source categories in the RECLAIM program. While these types of equipment/source categories are certainly in the	2-51

[5] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
[6] AQMD, Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.
[7] "RECLAIM Sources" data is computed from data presented in AQMD's RECLAIM Audit Report (March 2015). Command-and-control stationary sources NOx emissions is computed from data presented in AQMD Air Quality Management Plans (1997, 2003, 2007, 2012) and AQMP NOx RECLAIM Working Group Meeting #5, Agenda Item #3.

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	RECLAIM program, the program is a market-based program; not a command-and-control program. Furthermore, the stated objectives of Control Measure CMB-01 Phase I and Phase II which this rulemaking intends to implement are for **programmatic equivalency**. Since this is a market-based system, it cannot be assumed that all impacts from the proposed rulemaking will be exclusively borne by specific equipment/source categories even where AQMD Staff have clearly attempted to target those impacts on specific facilities as is clearly the case here. The language in the referenced section needs to be revised to reflect that (a) proposed project is seeking programmatic equivalency <u>within the requirements and limitations of the California Health & Safety Code</u> and (b) acknowledge that there may be impacts on other RECLAIM facilities given the market-based design of the RECLAIM program. Those impacts must be analyzed to the extent practicable.	2-51 Con't
Page 1-2, 2nd full paragraph	As discussed above (see comments on Page 1-1, 4th paragraph), the Draft PEA must be revised to address inconsistencies between the AQMD Staff's proposal and the project objectives.	2-52
Page 1-13, Table 1-1, Areas of Controversy Line 1, Amount of proposed NOx shave and availability of RTCs	Draft PEA claims "The staff analysis shows that after the proposed shave is imposed, there will be sufficient NOx RTCs available to maintain trading within the NOx RECLAIM program given foreseeable opportunities for emissions reductions." This statement is without technical foundation; neither the PEA nor the PDSR includes such a market analysis. On the contrary, the Staff's proposal would reduce the quantity of RECLAIM Trading Credit (RTCs) to levels without historical precedent and that action, according to Staff's own analysis, would result in a level of "unused" RTCs (i.e., RTCs not used to cover facility emissions) for which the only historical precedent was observed during the RECLAIM market collapse during the California power crisis of 2000-2001.[8] WSPA and the Industry RECLAIM Coalition have repeatedly expressed concerns about shaving the RECLAIM program to this level when such action is clearly beyond what is needed for BARCT equivalency and in conflict with California Health & Safety Code requirements. Table 1-1 must be revised to accurately reflect the actual technical record; not assert conclusions without technical foundation.	2-53
Page 1-14, Table 1-1, Areas of Controversy Line 2, Equity of proposed NOx shave	The Draft PEA states that for 210 facilities holding 10% of the available NOx RTCs that "no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified…for the types of equipment and source categories." This statement is factually incorrect and should be corrected. In actuality, AQMD Staff <u>elected not to review</u> BARCT for these facilities under this RECLAIM rulemaking. And contrary to the statement, AQMD and other California air districts have previously made BARCT determinations that do apply to the types of equipment and operations at those smaller emitting facilities (e.g., boilers, heaters, etc.) were they not under RECLAIM.[9]	2-54

[8] AQMD Annual RECLAIM Audit Report, March 2015.
[9] See SCAQMD Regulation XI for examples.

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Page 1-14, Table 1-1, Areas of Controversy Line 3, Results of the BARCT analysis	The Draft PEA states "While staff believes the engineering assumptions in the staff BARCT analysis are appropriate, the difference in BARCT reductions attributable to the alternate engineering assumptions suggested by the consultant is relatively small. To account for this difference and to provide a compliance margin, staff is proposing a shave of 14 tpd, reduced from the initial BARCT result of 14.85 tpd." We disagree. There continues to be a significant number of unresolved issues which result in uncertainty in the Staff's BARCT analysis as presented in the PDSR. This includes, but is not limited to the Staff's decision to selectively ignore the findings of the agreed upon third-party expert for the Refinery Sector, Norton Engineering Consultants. These issues are fundamental to the engineering design basis of the Staff's proposed BARCT determinations for most refinery sector source categories. These discrepancies were exhaustively described in Norton Engineering's expert analysis of the AQMD Staff's analysis,[10] as well as reiterated in NEC's letters dated 10 August 2015[11] and 4 September 2015.[12] Norton's comments are incorporated herein by reference. Furthermore, Staff's "after-the-fact" 0.85 TPD adjustment to the overall shave (i.e., reduces proposed shave from 14.85 to 14.0 TPD) is an improper application of the adjustments necessitated by Norton Engineering's expert findings. Such an adjustment, which is necessary, must be applied to the quantity of BARCT equivalency emission reductions attributed to refinery sector source categories. By failing to properly adjust this value, the AQMD Staff have distorted their own methodology to increase the burden of this shave on one sector (i.e., refineries). This is disproportionate and without technical foundation.	2-55

[10] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[11] James Norton, NEC, letter to Dr. Phillip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.
[12] James Norton, NEC, letter to Dr. Phillip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for Fired Heaters & Boilers Document No. 14-045-8, 4 September 2015.

Page 1-14, Table 1-1, Areas of Controversy Line 4, Equivalency with command-and-control	The Draft PEA asserts that the proposed shave amount of 14 tpd is consistent with previous RECLAIM rule amendments, the California Health & Safety Code, and the purpose of the program. As noted above (see above comments on Page 1-1, 4th paragraph), the AQMD Staff have not demonstrated that the Staff proposal is consistent with certain provisions of the California Health & Safety Code. Table 1-1, Line 4 must be revised to describe how the Staff proposal will comply with the project objective requiring compliance with all applicable H&SC requirements. The Draft PEA goes on to state "…This approach will result in approximately 8.79 tons per day of BARCT reductions of actual NOx emissions attributable to installing and operating additional controls. Otherwise, actual emissions reductions of only about two tpd over the next seven years would be achieved." WSPA agrees that under the AQMD Staff's analysis, BARCT equivalency as currently presented is not more than 8.79 TPD. And with adjustments needed to fully account for the findings of the AQMD's third-party refinery expert, Norton Engineering, the shave needed for BARCT equivalency is not more than 7.94 TPD.[13] Staff has provided no information to support the assertion that 14 TPD must be shaved to achieve the 8.79 TPD (or 7.94 TPD) required for BARCT equivalency. And RECLAIM program history does not support that conclusion. Under the 2005 Shave, a 23% reduction in RTCs resulted in a 24% reduction in NOx RECLAIM emissions; a nearly 1:1 relationship.[14] The Staff proposal must be revised to reflect the project objective of BARCT equivalency. That has not been demonstrated as any more than 8.79 TPD.	2-56
Page 1-15, Table 1-1, Areas of Controversy Line 5, 2012 AQMP Commitment in the State Implementation Plan (SIP)	The Draft PEA states: "This staff proposal recommends a reasonably available 14 tpd of NOx RTC reductions, based on BARCT, as required by state law." In fact, the PDSR presents BARCT equivalency as not more than 8.79 TPD, and the AQMD Staff have not explained how its proposal will comply with H&SC §40406, since there is no consideration of the economic impacts which would be incurred under a 14 TPD market adjustment that goes beyond BARCT. Furthermore, AQMD Staff's proposal is contrary to H&SC §39616(c)(1), which requires the market to perform at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment. The Draft PEA must be revised to fully demonstrated compliance with the project objectives and relevant H&SC requirements.	2-57

[13] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.

[14] SCAQMD Annual RECLAIM Audit Report, March 2015. Under the 2005 shave, RTCs were reduced from 34.2 to 26.5 TPD between 2005 and 2011 and emissions declined from 26.4 to 20 TPD over the same period.

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Page 1-16, Table 1-1, Areas of Controversy Line 6, Availability of RTCs for future power plant needs	The Draft PEA states" The staff proposal would establish a separate adjustment account to hold RTCs for power plants to meet their NSR holding obligations. Many newer peaking plants are required to hold RTCs at the potential to emit level each year even though their actual emissions are far below this level. The adjustment account would relieve power producing facilities from the obligation of holding RTCs in order to meet the NSR holding requirements of Rule 2005." The AQMD Staff proposal for a separate "adjustment account" has not been fully defined, and the Staff proposal and Draft PEA fail to address how such a mechanism would comply with U.S. EPA requirements for New Source Review. The PDSR and Draft PEA must be revised to demonstrate how such a proposed adjustment account would function, and demonstrate that it is approvable by U.S. EPA. Furthermore, Staff's proposal would apparently not apply to new peaking power plants. The California Air Resources Board prepared assessment of electrical grid reliability needs in the South Coast air basin which suggested a significant amount of peaking power plant capacity would be needed to ensure reliability in the future.[15] This report was prepared in conjunction with the California's power sector regulators (i.e., California Public Utilities Commission, California Independent System Operator, and California Energy Commission). Contrary to the CARB report, AQMD Staff's analysis depends on a negative growth rate for power sector emissions and RTC demand. This is a significant difference. The Draft PEA should be revised to clarify that the Staff proposal would provide no relief to any new peaking power plants. The Draft PEA should also be revised to demonstrate how the Staff proposal will accommodate new power sector facilities which may be needed to ensure electric reliability and integration of renewable electricity. 2-58
Page 1-17, 3rd paragraph	The Draft PEA states "For the remaining 210 facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified for the types of equipment and source categories at these facilities." This statement is factually incorrect and should be revised. As noted above, AQMD Staff elected not to review BARCT for these smaller facilities for this RECLAIM rulemaking (i.e., no analysis was performed). 2-59

[15] CARB, Assembly Bill 1318: Assessment of Electrical Grid Reliability Needs and Offset Requirements in the South Coast Air Basin, Draft Final Report, October 2013.

Page 1-20, 1st paragraph, 3rd sentence Air Quality and Greenhouse Gases	The Draft PEA states "For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will affect 65 facilities plus the investors, who collectively hold 90 percent of the NOx RTC holdings." This paragraph suggests that the proposed project will be limited to specific facilities in the RECLAIM program. While the application of the shave may be limited to these facilities, the impacts of the proposed shave will be broader. RECLAIM is a market-based program; not a command-and-control program. Since this is a market-based system, it cannot be assumed that all impacts from the proposed rulemaking will be exclusively borne by specific equipment/source categories even where AQMD Staff have clearly attempted to target those impacts on specific facilities as is clearly the case here. For example, smaller facilities without Infinite Year Basis (IYB) RTC holdings may incur higher RTC prices to meet their future compliance obligations. Alternatively, such facilities may find themselves unable to purchase RTCs at any price similar to the RTC supply crisis observed during the 2000/2001 power crisis which nearly collapsed the RECLAIM program. Also, Staff has not considered potential impacts to new or expanding facilities which are required to participate in RECLAIM. Or the potential consequences to the regional economy if those facilities are unable to obtain RTC supply. Or the potential environmental impacts of those operations if they are forced to locate outside of the South Coast air basin where they would presumably be subjected to lessor regulation. These are all issues and impacts which have been identified and should be disclosed as potential impacts from the project. The Draft PEA must be revised to clarify that market impacts may be broader than intended or even recognized by Staff, and those impacts must be quantified to the extent possible.	2-60
Page 1-20, 2nd paragraph	The Draft PEA states "…only 44 facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact." The Draft PEA should be revised to present supporting analysis demonstrating how this conclusion was reached. RECLAIM is a market-based program; not a command-and-control program. Since this is a market-based system, it cannot be assumed that all impacts from the proposed rulemaking will be exclusively borne by specific equipment/source categories even where AQMD Staff have clearly attempted to target those impacts on specific facilities as is clearly the case here.	2-61
Table 1-3, Summary of Proposed Project & Alternatives Alternative 3	This table reports the NOx Reduction Potential (tons/day) for Alternative 3 at 8.00 TPD. As proposed by the Industry, RECLAIM Coalition, Alternative 3 would result in BARCT equivalent reductions. Using the AQMD Staff's latest BARCT analysis, which needs to be revised downward as discussed earlier herein, the Proposed NOx RTC "Shave" for this alternative should be 8.79 TPD. The Draft PEA should be revised.	2-62

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Table 1-3, Summary of Proposed Project & Alternatives Proposed Project Page 1-26	This table clearly shows that the AQMD Staff proposal, which would shave 14 TPD, would include removing 5.21 TPD of RTCs from the RECLAIM market that cannot be attributed to BARCT. The table even labels these 5.21 TPD as "NOx RTCs Needed to Fulfill Shave <u>Post-BARCT</u>." [Emphasis Added] This proposal is beyond BARCT. Furthermore, a 14 TPD shave reduction of the RECLAIM market could violate the project objectives under the California Health & Safety Code (H&SC). Contrary to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is absolutely no consideration of the economic impacts which would be incurred under a 14 TPD market adjustment that goes Beyond BARCT. Contrary to H&SC §39616(c)(1), AQMD Staff has failed to demonstrate that the RECLAIM program will result in an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment**. Staff has instead applied a cost effectiveness threshold for this RECLAIM rulemaking of $50,000 per ton of NOx reduction which is more than double the cost threshold used for command-and-control rules within the District (i.e., $22,500 per ton[16]). This clearly imposing a greater cost on RECLAIM sources than would be incurred under command and control regulations. Furthermore, Staff has proposed a market shave of 14 TPD which goes beyond BARCT. Under AQMD Staff's analysis, BARCT equivalency is currently presented as not more than 8.79 TPD. Even that value is overstated since adjustments needed to fully account for the findings of the AQMD's third-party refinery expert, Norton Engineering, would reduce the shave for BARCT equivalency to not more than 7.94 TPD.[17] Thus, RECLAIM facilities would have greater costs under the Staff proposal than would have been incurred under a command-and-control program. And contrary to H&SC §39616(c)(7), AQMD has failed to demonstrate that the RECLAIM program as amended will not result in disproportionate impacts, measured on an aggregate basis, to those stationary sources included in the program as compared to other permitted stationary sources in the District's plan for attainment. RECLAIM program sources have already reduced NOx emissions by 69% since 1994, whereas command-and-control stationary sources have only reduced NOx emissions by about 44% during that same period.[18] The BARCT levels being proposed by

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[16] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.

[17] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.

[18] "RECLAIM Sources" data is computed from data presented in AQMD's RECLAIM Audit Report (March 2015). Command-and-control stationary sources NOx emissions is computed from data presented in AQMD Air Quality

	AQMD Staff generally represent performance levels that have not been demonstrated as broadly achievable for the source categories in question. Furthermore, these performance levels go well beyond the command-and-control standards adopted by AQMD under Regulation XI (i.e., the District's command-and-control program), and are well beyond BARCT determinations made by other major California air agencies administering command-and-control programs (e.g., SJVAPCD, BAAQMD, etc.). For these reasons, the Draft PEA must be revised to address inconsistencies between the AQMD Staff's proposal and the project objectives.	2-63 Con't
Table 1-4, Comparison of Adverse Environmental Impacts of the Alternatives Row 3: Air Quality & GHGs	This table reports for Alternative 3 "Less operational NOx reductions than proposed project but not quantifiable." As correctly reported in Table 1-3, Alternative 3 would actually reduce emissions by 8.79 TPD so it clearly is quantifiable. Table 1-4 must be revised to correctly report the emission reduction potential for Alternative 3.	2-64
Table 1-4, Comparison of Adverse Environmental Impacts of the Alternatives Row 3: Air Quality & GHGs Page 1-29	For the proposed project, the table reports "Increases operational use of NH3 (a TAC) by 39.5 tpd." But for Alternative 3, the table reports that ammonia (NH3) use is not quantifiable. However, no evidence is provided to support that conclusion. In the alternatives air quality analysis, the District asserts that if Alternative 3 were implemented, it would be too difficult to predict the number of facilities that would install NOx control equipment. First, the District should have acknowledged the unpredictability of facilities implementing the proposed project, which is more aggressive and could trigger correspondingly more drastic business reactions. Instead, the District assumes there that all facilities will fall in line to install equipment as it predicts (i.e., command and control). Second, the likely NOx control installation projects can be quantified at a program level since it is a function of the same stoichiometric relationship used in the Staff's analysis for the proposed project. The Draft PEA should be revised to provide an estimate of the operational ammonia use for Alternative 3. Since this value will be lower than the proposed project, Alternative 3 would have lower ammonia emissions by comparison and would therefore be environmentally preferable on this issue. Is Staff's estimate for increased operational use of ammonia based on 8.79 TPD of NOx emission reductions (i.e., BARCT equivalency)? Since the Staff's 14 TPD proposal would require significantly greater emission reductions (i.e., beyond BARCT), the Draft PEA should be revised to explain the basis for this ammonia use figure to ensure that project's potential environmental impacts are fully disclosed. The ammonia figure also drives traffic and construction impacts which may be greater than disclosed in the Draft PEA. For similar reasons, the Staff's statement that Alternative 3 emissions for construction are "not quantifiable" is not accurate. As reported in Table 1-3, Alternative 3 would require emission controls sufficient to reduce NOx emissions by 8.79 TPD (again, using the Staff's BARCT analysis). The	2-65

Management Plans (1997, 2003, 2007, 2012) and AQMP NOx RECLAIM Working Group Meeting #5, Agenda Item #3.

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	Draft PEA must be revised to include a quantified estimate of the construction emissions needed to deliver those emissions control using a methodology similar to the Staff's analysis of the proposed project.	2-65 Con't
Table 1-4, Comparison of Adverse Environmental Impacts of the Alternatives Row 3: Air Quality & GHGs Page 1-30	The Alternative 3, the Draft PEA reports impacts are "Less than significant; achieves net NOx emission reductions during operation (less reductions than the proposed project but not quantifiable)." [emphasis added] This is not correct. As reported in Table 1-3, Alternative 3 would require emission controls sufficient to reduce NOx emissions by 8.79 TPD (again, using the Staff's BARCT analysis) so clearly the impacts from Alternative 3 are quantifiable. The Draft PEA must be revised to include a quantified estimate of the NOx emission reductions during operation for Alternative 3.	2-66
Page 2-2, Section 2.2 Project Objectives	The Draft PEA states: "The objectives of the proposed project are to: 1) Comply with the requirements in Health and Safety Code (HSC) §§40440 and 39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT; 2) Modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment; 3) Ensure that RECLAIM facilities, in aggregate, achieve the same emission reductions that would have occurred under a command-and-control approach; 4) Achieve the proposed NOx emission reduction commitments in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM; and, 5) Achieve NOx emission reductions to assist in attaining the NAAQS." This highlights several problems with the Draft PEA and the Staff proposal. WSPA agrees that AQMD has a legal obligation to comply with the requirements in Health and Safety Code (HSC) §§40440 and 39616. However, Staff has oversimplified what those obligations are by suggesting this is entirely about conducting a BARCT assessment. The AQMD Staff's proposed 14 TPD shave reduction from the RECLAIM market could violate the project objectives under the California Health & Safety Code (H&SC). With respect to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is no consideration of the economic impacts which would be incurred under a larger 14 TPD market adjustment that goes beyond BARCT. With respect to H&SC §39616(c)(1), AQMD Staff has failed to demonstrate that the RECLAIM program will result in an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the**	2-67

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	District's plan for attainment. Staff has instead applied a cost effectiveness threshold for this RECLAIM rulemaking of $50,000 per ton of NOx reduction which is more than double the cost threshold used for command-and-control rules within the District (i.e., $22,500 per ton[19]). This clearly imposes a greater cost on RECLAIM sources than would be incurred under command and control regulations. Furthermore, Staff has proposed a market shave of 14 TPD which goes beyond BARCT. Under AQMD Staff's analysis, BARCT equivalency is currently presented as not more than 8.79 TPD. Even that value is overstated since adjustments needed to fully account for the findings of the AQMD's third-party refinery expert, Norton Engineering, would reduce the shave for BARCT equivalency to not more than 7.94 TPD.[20] Thus, RECLAIM facilities would have greater costs under the Staff proposal than would have been incurred under a command-and-control program. And contrary to H&SC §39616(c)(7), AQMD has failed to demonstrate that the RECLAIM program as amended will not result in disproportionate impacts, measured on an aggregate basis, to those stationary sources included in the program as compared to other permitted stationary sources in the District's plan for attainment. RECLAIM program sources have already reduced NOx emissions by 69% since 1994, whereas command-and-control stationary sources have only reduced NOx emissions by about 44% during that same period.[21] The BARCT levels being proposed by AQMD Staff generally represent performance levels that have not been demonstrated as broadly achievable for the source categories in question. Furthermore, these performance levels go well beyond the command-and-control standards adopted by AQMD under Regulation XI (i.e., the District's command-and-control program), and are well beyond BARCT determinations made by other major California air agencies administering command-and-control programs (e.g., SJVAPCD, BAAQMD, etc.).	2-67 Con't

[19] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
[20] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.
[21] "RECLAIM Sources" data is computed from data presented in AQMD's RECLAIM Audit Report (March 2015). Command-and-control stationary sources NOx emissions is computed from data presented in AQMD Air Quality Management Plans (1997, 2003, 2007, 2012) and AQMP NOx RECLAIM Working Group Meeting #5, Agenda Item #3.

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Page 2-2, Section 2.2 Project Objectives (continued)	Next, the Draft PEA suggests an objective to "modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment."[21] That is not consistent with the project description contained in the Notice of Preparation issued 4 December 2014,[22] nor is it consistent with project description contained in the Initial Study.[23] Specifically, neither the NOP Project Description nor the Initial Study Project Description included any reference to modifying "the RECLAIM trading credit (RTC) "shaving" methodology" in the description of the project or the project objectives. And this is also inconsistent with the objectives approved by the Governing Board under Control Measure CMB-01. For these reasons, all references to "modifying "the RECLAIM trading credit (RTC) "shaving" methodology" should be removed from the Draft PEA.	2-67 Concluded
Page 2-2, Section 2.2 Project Objectives (continued)	This section also suggests an objective "Achieve NOx emission reductions to assist in attaining the NAAQS." This is also not consistent with the Project Description contained in the Notice of Preparation issued 4 December 2014,[24] or the description contained in the Initial Study Project Description.[25]	2-68

[22] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."

[23] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.

[24] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."

[25] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.

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Page 2-6, 4th paragraph	The Draft PEA states "the proposed project is estimated to reduce four tons per day of NOx emissions starting in 2016 because the amount of unused RTCs in the NOx RECLAIM program over the past five years (e.g., from 2009 to 2013) ranged from five tpd to eight tpd, demonstrating that there is enough cushion to support reduction of four tpd in 2016." While the quantities of "unused" RTCs are a matter of historical record, Staff has provided no evidence to support that supposition that the RECLAIM market has "enough cushion to support reduction of four tpd in 2016." And if this was just a reduction of unused RTCs, that would not equate to an emissions reduction in 4 TPD. The Draft PEA needs to be revised to include a market analysis to support that supposition or this statement should be deleted.	2-69
Page 2-6, 4th paragraph (continued)	The Draft PEA goes on to state "it could take from two to four years for the affected facilities to plan, obtain permits, and install air pollution control equipment or modify existing equipment in response to the proposed project." According to information from WSPA members, this estimate is too short.[26] While some individual projects might be complete able in 2-4 years, the proposed project would require dozens and dozens of emission control projects to be completed. For the refinery sector, such projects would need to be planned, engineered, and sequenced for construction in consideration of unit turnaround schedules. WSPA members report that completion of all needed projects for the proposed project would likely require not less than eight (8) years. The Draft PEA should be revised to reflect this timetable and the Proposed Amended Rules and PDSR should be similarly adjusted.	2-70
Page 2-9, PAR 2005 Requirements for New or Relocated RECLAIM Facilities – Subdivision (b)	The AQMD Staff have yet to provide a complete description of the amendments to this rule. AQMD Staff have also not obtained U.S. EPA approval that such amendments would even be approvable into the State Implementation Plan (SIP). The Draft PEA and PAR 2005 should be revised to reflect these important details <u>after</u> AQMD Staff have obtained the U.S. EPA approval needed for such amendments to be legal.	2-71
Page 2-10, top of page	The Draft PEA states "Further, only 44 facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact." The Draft PEA should be revised to present supporting analysis demonstrating how this conclusion was reached.	2-72
Page 3.2-34, 2nd paragraph, GHG Tailoring Rule	This section should be revised to note that the courts vacated significant portions of the GHG Tailoring Rule. The applicability criteria as described in the Draft PEA are not consistent with current regulations.	2-73
Page 4.1-3, Section 4.1.3.1	The Draft PEA states "Because each affected facility is located in heavy industrial areas, the construction equipment is not expected to be substantially discernable from what exists on-site for routine operations and maintenance activities. Further, the construction activities are not expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities are expected to occur within the confines of each existing facility and are expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility."	2-74

[26] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.

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	This statement oversimplifies the range of physical settings existent for RECLAIM facilities. In actuality, some refinery or non-refinery RECLAIM facilities are located areas where additional vertical obstructions from cranes or new emission control structures could be "discernable" and may adversely impact views and aesthetics resources for adjacent communities. The Draft PEA should be revised to clarify the range of settings which would be impacted by the proposed project and acknowledge the range of potential impacts associated with the proposed project.
Page 4.2-2, Table 4.2-1 Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category	As shown in this table, the Draft PEA states that Staff has assumed 74 SCRs would be installed on Refinery Process Heaters and Boilers under the proposed project. Staff does not explain the basis for this value, which conflicts with the Preliminary Draft Staff Report (PDSR). The PDSR suggests that the proposed project would result in 76 SCRs (25 upgraded, 51 new) for refinery heaters and boilers,[27] in which case the Draft PEA would be understating the potential project impacts. It should also be noted that AQMD's third-party refinery sector expert, Norton Engineering, found that only 48 refinery heaters and boilers could be cost effectively retrofit with new or upgraded SCRs.[28] Staff have done nothing to reconcile this discrepancy which is material. The Draft PEA must be revised to clarify the technical basis for the assumed emission controls outcome and associated potential impacts to the environment. The Draft PEA should also explain how emission controls which are not cost effective, according to AQMD's own third-party expert, will be implemented. 2-75
Page 4.2-4, Section 4.2.3.1, first paragraph	The Draft PEA states "Further, operators at each affected facility who construct NOx control equipment that utilize chemicals as part of the NOx control equipment operations, such as a new ammonia or caustic storage tank, may also need to build a containment berm large enough to hold 110 percent of the tank capacity in the event of an accidental release, pursuant to U.S. EPA's spill prevention control and countermeasure regulations." While other regulations and good engineering practices would require containment features for these tanks, the Spill Prevention Control and Countermeasure (SPCC) regulations actually don't apply to ammonia or caustic storage vessels. The Draft PEA should be clarified accordingly. 2-76
Page 4.2-7, last paragraph	The Draft PEA states "if a particular technology was identified as having a cost that exceeds $50,000 per ton, this CEQA analysis assumed that the facility operator would not install this type of air pollution control technology in response to the project." This statement is inconsistent with the project objectives which require compliance with the California Health & Safety Code. The $50,000 threshold fails in this regard. Under H&SC§39616(c)(1), the RECLAIM program is required to result in "an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations** and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment." AQMD Staff has failed to demonstrate that the proposed amended RECLAIM program will be **at equivalent or less** 2-77

[27] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, Table B.10.
[28] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, Table B.9.

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	cost compared with current command and control regulations. On the contrary, Staff's proposed $50,000 cost effectiveness threshold for this RECLAIM rulemaking is more than double the cost threshold used by AQMD for command-and-control rules (i.e., $22,500 per ton[29]). This clearly imposes a greater cost on RECLAIM sources than would be incurred under command and control regulations. The Draft PEA and Proposed Amended Rules must be revised is be consistent with the project objectives and all applicable H&SC requirements.	2-77 Con't
Page 4.2-8, Section 4.2.3.1, first paragraph	The Draft PEA states "In order to operate SCR and UltraCat technology, ammonia is necessary and, as such, tanks to store ammonia would also need to be installed. The size of each ammonia tank needed to operate the SCR units and one UltraCat filtration unit have been estimated to range between 2,000 and 11,000 gallons in capacity." While this statement may be appropriate for characterizing new tanks which are likely to handle aqueous ammonia, it ignores the fact that some existing ammonia tanks are used to store anhydrous ammonia. The PEA should be revised to address this description. Staff should consider whether this condition requires revision of the offsite consequence analysis presented in the Draft PEA.	2-78
Page 4.2-8, Section 4.2.3.1, 5th paragraph	The Draft PEA states "From a construction point of view, the installation of a NOx control technology at a refinery is a complex process. For example, if a facility operator chooses to install NOx control equipment, time will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential control equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and scheduling contractors and workers. The amount of lead time can vary from six months (e.g., for a SCR for refinery/boiler heater or gas turbine) to up to 18 months for a scrubber (either a WGS or DGS)." AQMD permitting for new emission controls can easily take as much as 18 months for Title V facilities. This could easily increase the amount of lead time a company requires to 2-3 years. Some of the pre-construction activities cannot be conducted until the Permit to Construct has been issued.	2-79
Page 4.2-11, top of page	The Draft PEA states "…the analysis also includes an analysis of the overlapping impacts spread out over a five- and seven-year period." According to information from WSPA members, this estimate is too short. While some individual projects might be complete able in 2-4 years, the proposed project would require dozens and dozens of emission control projects to be completed. For the refinery sector, such projects would need to be planned, engineered, and sequenced for construction in consideration of unit turnaround schedules. WSPA members report that completion of all needed projects for the proposed project would likely require not less than eight (8) years.[30] The Draft PEA should be revised to reflect this timetable and the Proposed Amended Rules and PDSR should be similarly adjusted.	2-80

[29] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
[30] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.

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Page 4.2-13, 1st paragraph Combined Construction Emissions From Non-Refinery and Refinery Facilities	The Draft PEA does not disclose the assumed basis for construction impact estimates. Are these impacts based on construction of emission controls to deliver 8.79 TPD (i.e., BARCT equivalency), or has Staff assumed construction sufficient to deliver the proposed 14 TPD of emission reductions (i.e., beyond BARCT equivalency)? The amount of construction activity for modification of existing SCRs will be different than the activity needed for entirely new SCR installations. The Draft PEA must be revised to fully disclose the technical basis of this analysis so the public can understand whether the impacts presented are complete.	2-81
Page 4.2-13, last paragraph Combined Construction Emissions From Non-Refinery and Refinery Facilities	The Draft PEA notes "…it is likely that only minimal, if any, construction activities would occur at any refinery facilities during 2016." This is exactly why the Staff proposal to remove four (4) TPD of RTCs in 2016 is too much, too fast. Staff has provided no evidence to support that supposition that the RECLAIM market has "enough cushion to support reduction of four tpd in 2016."	2-82
Page 4.2-18, 1st paragraph	The Draft PEA states "Implementation of the proposed project is expected to result in direct air quality benefits from the reduction of 14 tons per day of NOx RTCs by 2022. Because of the RECLAIM market system, the actual reduction in NOx emissions each year may be less than the reduction in RTC holdings imposed by the project." This statement conflicts with Page 1-1, 4th paragraph. Please see our comment to that prior statement.	2-83
Page 4.2-20, Refinery Facilities	This section presents impacts from operation of the proposed project for refinery facilities in the South Coast air basin. The Draft PEA does not disclose the assumed basis for these impact estimates. Are these impacts based on operation of emission controls to deliver 8.79 TPD (i.e., BARCT equivalency), or has Staff assumed operations sufficient to deliver the proposed 14 TPD of emission reductions (i.e., beyond BARCT equivalency)? The Draft PEA should be revised to explain the basis of the technical analysis so the public can understand whether the impacts presented are complete.	2-84
Page 4.2-22, 1st paragraph	The Draft PEA states "Ammonia slip is limited to five parts per million (ppm) by permit condition." This is an oversimplification since some existing SCRs are permitted with higher ammonia slip limits. These existing units may not be required to open their permits, in which case they could continue to operate with higher than 5 ppmv ammonia slip performance. Furthermore, the Draft PEA analysis of ammonia slip for new SCR installations depends on physical conditions which the Staff analysis explicitly omitted from the project description (e.g., use of Ammonia Slip Catalysts or ASC) despite recommendations by the AQMD's third-party expert, Norton Engineering, to use ASC.[31] Without the ASC, ammonia slip from individual devices could be as great as 20 ppmv, but the draft PEA underestimates the ammonia slip by assuming it will universally be 5 ppmv. However, existing SCRs are not necessarily subject to those permit	2-85

[31] Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Table 2-3.

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	conditions, and thus, ammonia slip of up to 20 ppmv should be considered in the health risk assessment for ammonia emissions.[32] The Draft PEA should be revised to more accurately reflect the range of ammonia slip conditions which could exist. Importantly, the screening Health Risk Assessment results presented in the Draft PEA would need to be revised to reflect that broad range of ammonia slip performance.	2-85 Con't
Section 4.2.4, Cumulative Air Quality Impacts	The Draft PEA does not discuss the potential secondary impacts on air quality associated with increased emissions of ammonia from the numerous SCRs mandated by this rulemaking. Ammonia is a precursor to PM2.5 formation for which the South Coast AQMD is in nonattainment, so the PEA should consider whether additional ammonia emissions would represent a cumulatively considerable impact.	2-86
Page 4.2-26, 1st full paragraph	The Draft PEA states "…based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, is anticipated to bring the District into attainment with all national and most state ambient air quality standards by the year 2023." This statement is at best incorrect. A significant portion of the control strategy presented in the 2012 AQMP was still 182(e) "black box" measures which have not been defined.	2-87
Chapter 5, Alternatives	In this section, the Draft PEA presents 5 alternatives to the proposed project, but except for Alternative 4 (No Project) and Alternative 3 (Industry Approach), all other alternatives propose 14 TPD or more of NOx emission reductions. Given that the proposed project has remaining significant environmental effects with the proposed project at 14 TPD, the failure to include any additional alternatives other than Alternative 3 (Industry Approach) at a lesser reduction of NOx emissions does not satisfy CEQA's requirement for a "reasonable range of alternatives." In addition, the Draft PEA repeatedly claims that the impacts from the alternatives are "not quantifiable" for unspecified reasons. But these figures are not unknowable. In most cases, Staff could have easily made bounding or other technical assumptions to complete the quantification to allow the public to understand how the impacts from the alternatives compare to the Staff's proposed project. The Draft PEA must be revised to include this additional technical detail.	2-88

[32] Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Tables 4.2-18 and 4.2-21.

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WSPA

Western States Petroleum Association

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Sue Gornick
Senior Coordinator, Southern California Region

VIA ELECTRONIC MAIL

May 27, 2015

Dr. Barry Wallerstein
Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: WSPA COMMENTS ON APRIL 29, 2015 SCAQMD NOX RECLAIM WORKING GROUP MEETING

Dear Dr. Wallerstein:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-six companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the Regional Clean Air Incentives Market (RECLAIM) program.

On May 15, 2015 we submitted a letter specifically focused on the District's shave approaches under consideration and strongly confirmed our support of an equally distributed "across-the board" reduction in RECLAIM NOx credits. This letter provides additional comments on the remaining proposals presented by Staff on April 29, 2015 during the NOx RECLAIM Working Group meeting. We highlight our key issues below.

2-89

Incremental Best Achievable Retrofit Control Technology (BARCT) Method as a CEQA Alternative

WSPA is a part of the Industry RECLAIM Coalition, and we have presented an alternative formula to determine the size of the shave. The Coalition believes our alternative method is consistent with the Health & Safety Code provisions for a market-based system; reflects advances in emission control technology; achieves real emission reductions; more than fulfills the commitments made in the 2012 Air Quality Management Plan (AQMP); preserves the successful RECLAIM program; and achieves all the above in a more cost-efficient manner than the District's Remaining Emissions proposal.

On January 30, 2015, the Coalition submitted comments on the Notice of Preparation and Initial Study (NOP/IS) for a Draft Program Environmental Assessment (PEA) requesting that at least two project alternatives be considered. Based on the information presented at the April 29, 2015 working group meeting, and subsequently with the document released on May 15, 2015 entitled, "SCAQMD NOx RECLAIM Proposed Shave Approaches", WSPA reiterates this request. The May 15th document only addresses how a 14.85 RECLAIM Trading Credits (RTC) reduction could be implemented. WSPA requests that the PEA include alternative emissions reductions, including the proposed Industry alternative approach, currently estimated at 8.8 tpd based on the District's most recent BARCT determinations. We believe the Incremental BARCT method recognizes the importance and economic value of the allowance market and, hence, must be included for an adequate Staff and CEQA analysis.

WSPA requests that the SCAQMD include an analysis of the Industry Coalition's Incremental BARCT method in the Draft PEA when it is published in the coming months. As the Initial Study acknowledges, the Draft PEA must discuss and compare a reasonable range of alternatives, in addition to the proposed project. Alternatives must be feasible as defined by CEQA (CEQA Guidelines § 15364) and must attain the basic objectives of the proposed project and avoid or substantially lessen adverse environmental impacts of the project as proposed (CEQA Guidelines § 15126.6). *See also City of Long Beach v. Los Angeles Unified School Dist.* (2009) 176 Cal.App.4th 889, 920. The lead agency bears the burden of adequately presenting and analyzing alternatives. *See Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 405. The CEQA document must provide an "in-depth discussion of those alternatives identified as at least possibly feasible." *See Preservation Action Council v. City of San Jose* (2006) 141 Cal.App.4th 1336, 1350; *Sierra Club v. County of Napa* (2004) 121 Cal.App.4th 1490.

The Incremental BARCT method would result in RTC reductions greater than the approved SCAQMD control measures, but would lessen significant impacts from compliance with the District's proposed shave methodology. The Initial Study identifies numerous potentially significant impacts associated with the installation and operation of emission control equipment as required by the project as proposed. These include impacts to aesthetics (visual impacts of control equipment), air quality and greenhouse gases (increased construction emissions from NOx control equipment installation; operational emissions from control equipment and its support equipment, and from trucks delivering supplies and hauling waste), energy (energy demand for construction and operation of control equipment), hazards and hazardous materials (use and transport of catalysts and scrubbing agents used by control equipment, in particular use of acutely hazardous ammonia in SCR and SNCR technologies), hydrology and water quality (risk of spills of toxic chemicals including ammonia), solid and hazardous waste (solid and hazardous waste generation from construction activities), and transportation and traffic (from truck trips associated with construction activity). The Incremental BARCT method can achieve basic project objectives while reducing these impacts, and so should be fully evaluated as a reasonable and feasible alternative in the forthcoming PEA.

2-89
Concluded

2

Alternatives also must be feasible, and one of the elements of "feasibility" as defined by CEQA is economic feasibility (CEQA Guidelines § 15364). The Incremental BARCT method constitutes a feasible alternative that would avoid or reduce the excessive costs of the project as proposed. The District's shave methodology not only includes a reduction in allowances due to a BARCT assessment for new technology, it also removes a considerable amount of allowances beyond what is justified by BARCT advancement. Staff's graph entitled, "BARCT Costs for Refinery Sector", estimated BARCT costs for all five categories of refinery equipment to be $741 million for 6.06 tons/day of NO_x reductions with an average cost of $13,200 per ton of NO_x reduced using the discounted cash flow (DCF) method. However, Staff did not include the cost of reductions for the approximately 6 tons of RTCs that are shaved beyond BARCT. WSPA regards this omission as a significant issue that must be addressed by the SCAQMD Staff analysis and in the CEQA analysis of the proposed project in comparison to alternatives. Simply ascribing zero costs to the additional 6 tpd market shave beyond BARCT is not appropriate. On the contrary, given that the cost of achieving the first 6.06 tpd of NOx reductions is $741 million, the cost of an additional 6 tpd increase must be substantial. If the District has data indicating that the additional 6 tpd could be achievable at a reasonable and feasible cost, it is the District's burden to provide that information and incorporate it into both the CEQA alternatives analysis and the analysis of cost effectiveness. 2-90

<u>Shave Methodology and Estimation</u>

Concerns with the District's method and costs estimates include:

- The District's 2023 remaining emissions calculation includes a growth factor for the non-refinery sectors, BARCT adjustments for shutdown glass facilities and from the CPCC (after BARCT adjustment with growth), remaining emissions from new facilities from the 2005 NO_x RECLAIM amendments, and a 10% adjustment factor applied to refinery, non-refinery, and new facility emissions only. WSPA recommends that a more appropriate compliance margin is 30% or 3.08 tpd. This amount is consistent with the historical unused RTC trend that ranged from 5.1 tpd to 9.1 tpd between 2005 and 2013.[1]
- WSPA recommends that the RTCs derived from ERC conversions be exempted from the proposed shave. According to SCAQMD's 1996 annual RECLAIM audit report, the original RTC amount is 2.6 tpd[2]. With the adjustment for the 2005 shave, the amount for the exemption proposed is 2.01 tpd (i.e. 7.6% of the current RTC market).
- The October 2013 AB 1318 Air Resources Board draft final report[3] stated on page 65 (Table II-5) that the estimated offset needs for once-through cooling power plant replacements and new greenfield generation are 8.23 NO_x tons/day. This does not appear to be included in Staff's adjustment factors. How will the District accommodate the 8.23 tons/day requirement with the approximately 2 tons/day allowance shown for power providers?

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[1] SCAQMD, Annual RECLAIM Audit Report.

[2] Table 2-1, NOx Allocation Adjustments, SCAQMD Annual RECLAIM Program Audit Report, January 1996.

[3] Air Resources Board Draft Final Report: Assembly Bill 1318: Assessment of Electrical Grid Reliability Needs and Offset Requirements in the South Coast Air Basin, October 2013.

3

Useful Life of Control Equipment

Abt Associates recently conducted a third-party review of the District's socioeconomic assessment process[4] and recommended that AQMD "appropriately consider useful life of pollution control equipment" to "ensure that compliance deadlines are set such that control equipment is not required to be replaced before end of useful life." In response to this finding, SCAQMD Staff committed to consider equipment life on a case-by-case basis, attempt to avoid stranded assets, and in cases of stranded assets, include equipment replacement costs and salvage values in the socioeconomic analysis.[5]

SCAQMD Staff stated at the Working Group meeting[6] their intention to estimate a useful life of 25 years for the BARCT control equipment review for all source categories under this rulemaking (i.e., refinery and all non-refinery sources). While we agree that certain **emission control equipment** may in theory have a useful life of 25 years, we believe that the economic useful life is more appropriately linked to the adoption frequency of new **control measures.** The regularity with which regulations are being promulgated indicates that the appropriate useful life of an SCR is more likely on the order of 10 years. WSPA's analysis also includes review of other Air Districts in California that support our recommendation.

For example, although Staff presented the Bay Area's useful life of 20 years, this is based only on a rule currently in development. The Bay Area's current BACT Guidelines actually recommend 10 years[7]. Additionally, both the San Joaquin Valley[8] and San Diego County[9] use 10 years. In fact, the South Coast's own Best Available Control Technology Guidelines[10] (BACT) recommends a 10 year useful life.

Staff stated that useful life is solely based on actual equipment life and not economic life. The Staff position does not take into consideration the regularity with which new rules are promulgated and the significant impact that using the 25-year period has on the District's cost effectiveness calculation. By using the District's recommendation for useful life, the costs are amortized over 25 years, rather than recognizing the fact that the last shave was in 2005, and control equipment can potentially be required to be replaced well before 25 years. The useful life of the equipment is simply not relevant when AQMD rulemaking necessitates the upgrade or replacement of equipment on an earlier timetable. In fact, both a useful life of 10 years (non-refinery) and a useful life of 25 years (refinery) were used during the 2005 shave. Therefore, WSPA recommends that Staff recommend a 10-year useful life for Selective Catalytic Reduction (SCR) control equipment. Staff should also include in their CEQA analysis the cost 2-91

[4] Abt Associates, Review of the SCAQMD Socioeconomic Assessments, Documentation Tasks 1-4, August 2014.
[5] SCAQMD, Summary of Abt Recommendations & SCAQMD Staff Response, November 2014.
[6] Staff presentation slides from NOx RECLAIM Working Group Meeting, 29 April 2015.
[7] BAAQMD, BACT guideline (http://hank.baaqmd.gov/pmt/bactworkbook/).
[8] SJVAPCD, Revised BACT Cost Effectiveness Thresholds, 14 May 2008; BACT Guidelines and Policy APR 2015.
[9] SDCAPCD, NEW SOURCE REVIEW REQUIREMENTS FOR BEST AVAILABLE CONTROL TECHNOLOGY (BACT) GUIDANCE DOCUMENT, 2011.
[10] SCAQMD, Best Available Control Technology Guidelines, Part C: Policy and Procedures for Non-Major Polluting Facilities, 2006.

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effectiveness evaluation using a 10-year period[11]. Because SCAQMD is ultimately responsible for making findings and determinations as to the proposal's feasibility, as well as the feasibility of other alternatives, this cost-effectiveness analysis is critical to the CEQA analysis. *See Preservation Action Council v. City of San Jose* (2006) 141 Cal.App.4th 1336, 1356; *see also Flanders Foundation v. City of Carmel-by-the-Sea* (2012) 202 Cal.App.4th 603, 618. 2-91 Concluded

Emission Reductions and Remaining Emissions

Staff presented two tables at the April 29, 2015 Working Group that detailed the emission reductions and remaining emissions for the refinery sector, power plants and non-power plants. Minor changes were noted in the refinery sector and non-power plant sector, however, modifications to the growth factor and base year for the power sector significantly reduced the 2023 Emissions at 2015 BARCT for that category. WSPA requests the data supporting these modifications.

BARCT Costs for the Refinery Sector and Cost Effectiveness Summary

- Staff indicated that they disagreed with the cost data and conclusions from their third party engineering consultant, Norton Engineering. Specifically, the SCR equipment costs were based only on one data point from one refinery and the recommendation was for double the SCR catalyst. As a result, Staff indicated that they dismissed the data and instead used their own cost data derived through their own analysis (i.e. field data for SCR installations, discussions with vendors, and literature reviews). WSPA is troubled by the selective dismissal of the third party engineering analysis which is meant to assure a reliable and transparent process during rulemaking. Additionally, while we appreciate the discussion provided at the April 29, 2015 Working Group, there are several unresolved questions. They are:
    - Since the dismissed cost data will impact a specific engineering recommendation (i.e. length of catalyst beds), how will performance be guaranteed to meet the new BARCT levels proposed?
    - What are the specific cost details that were modified and how does that impact cost effectiveness?
    - How will third party evaluations be treated in the future to ensure a transparent process?
- WSPA met with Staff on April 10, 2015 to discuss the BARCT assessment for refinery heaters & boilers and explained that we believe the District has miscalculated the cost effectiveness for a number of refinery heaters. Specifically, there were 10 heaters in the Staff's BARCT analysis tables dated 2 February 2015[12] where the cost effectiveness of proposed BARCT was analyzed based on an inappropriate cost baseline. That cost baseline assumed the presence of SCR technology where prior BARCT determinations had not been based on SCR technology. Correction of this error would render most of these units not cost effective. Furthermore, if the Staff disregard the conclusion from the Norton's third-party

[11] SCAQMD, Staff Report for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), January 2005.

[12] SCAQMD, Preliminary Cost Effectiveness Summary, Attachment B (Refinery Heaters), transmitted to WSPA via email, 2 Feb 2015.

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expert report (as suggested to WSPA on 10 April), nearly 40 units would be impacted by this analysis error.[13]

- In reviewing the BARCT costs for the Refinery Sector presented at the Working Group, we are unable to discern if Staff considered our request for changes as outlined in our April 22, 2015 letter. Therefore, WSPA requests the data used to compile these costs.
- At the April 10, 2015 SCAQMD – WSPA meeting, we also discussed various other issues we have with the Staff's NOx RECLAIM shave proposal. One of the topics included the Staff's use of the discounted cash flow (DCF) method instead of the levelized cash flow (LCF) method as used by several other Air Districts. Staff did provide the LCF analysis as a comparison to the DCF method at the Working Group. WSPA believes that the LCF method is a better representation of cost effectiveness than the DCF method. Accordingly, WSPA recommends that the LCF method be used for the rule as well as the same cost effectiveness threshold of $50,000/ton (as currently indicated for the DCF method).

<u>Preliminary BARCT Analysis</u>

- WSPA understands that BARCT should represent a level of performance which is technically feasible and cost effective for most units on a retrofit basis in a given source category. Based on the data provided to the Working Group by Staff, it does not appear that 2 ppm is an acceptable BARCT determination for refinery heaters and boilers. The data provided by Staff and confirmed by a confidential WSPA survey[14], conducted by a third party contractor, suggests that less than 6.5% of the existing refinery heaters and boilers which have been retrofitted with SCR technology, are currently performing at or below 2 ppm[15]. This includes a number of units which had been retrofitted in recent years. This does not represent a considerable proportion of the units in this source category. (In fact, only 3.5% of new installations can meet 2 ppm).
- WSPA recommends that 5 ppm is a more appropriate endpoint for refinery boilers/heaters because of the following reasons:
  - Currently, there are 87 installed SCRs of the 212 total boilers and heaters[16]. As noted above, WSPA's confidential survey indicates that only two of the four heaters that SCAQMD identified as performing below 2 ppm NOx are retrofitted units (i.e. with SCR). This represents only 6.5% of the total retrofitted units (31 units). Additionally, only one more retrofitted unit performs between 2 ppm and 5 ppm.
  - As presented by combustion expert, Rich Smirnoff at our April 10, 2015 meeting[17]:
    - Current commercial burner technology typically produces 16-20 ppm NOx @ 3% O2 in ideal furnace conditions, as in burner test furnaces, with single burners. A target NOx reduction of 90% may not be sufficient if the heater produces 30 ppm NOx.

[13] SCAQMD, Preliminary Analysis – Refinery Boilers/Heaters, July 2014 (posted on AQMD website October 2014).
[14] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, Mar 2015.
[15] SCAQMD, NOx RECLAIM Working Group Meeting, 19 September 2013.
[16] SCAQMD, NOx RECLAIM Working Group Meeting, 19 September 2013.
[17] "Refinery Fired Heaters, NOx Emissions Reductions Retrofit Limitations", presented by Rich Smirnoff, April 10, 2015 at WSPA-AQMD meeting.

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  - When burning natural gas, the fuel heating value is constant and furnace adjustments can be set with minimal difficulties. However, when burning refinery gas, the heating value will vary significantly.
- The NEC report, as represented at the January 2015 SCAQMD NOx RECLAIM Working Group meeting, indicates that 5 to 10 ppm NOx is feasible for calciner sources. However, given that the technology is unproven in a calciner situation, WSPA recommends that even a higher BARCT endpoint than 10 ppm may be warranted.

Energy Efficiency Projects

Staff presented a slide on Energy Efficiency Projects that stated there could be an additional 0.7 tpd NOx reductions from energy efficiency projects completed from 2007, yet not included in the inventory baseline. WSPA opposes any attempt to include this additional tpd as the projects and benefits reported under the energy efficiency and co-benefits reports would have been largely, if not entirely, reflected in the 2011 emissions baseline being used for this rulemaking. In short, any co-benefits contained in those reports are not additive.

Thank you for considering the comments addressed in this letter. We look forward to continuing to work with you and your Staff on this important rulemaking.

Sincerely,

Suzanne E. Bornicki

cc: Phil Fine
Joe Casmassi
SCAQMD Board Assistants

7

Credible Solutions • Responsive Service • Since 1907

Sue Gornick
Senior Coordinator, Southern California Region

VIA ELECTRONIC MAIL

August 21, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: WSPA COMMENTS ON PRELIMINARY DRAFT STAFF REPORT (PDSR) FOR NOX RECLAIM AMENDMENTS DATED JULY 21, 2015

Dear Dr. Fine:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the Regional Clean Air Incentives Market (RECLAIM) program.

WSPA and the Industry RECLAIM Coalition (of which we are a member) have submitted several comment letters during this rulemaking process to request changes to the District Staff's proposal that we believe are necessary to preserve a healthy and successful RECLAIM program for all RECLAIM participants, as well as to satisfy the 2012 AQMP commitments to the State Implementation Plan (SIP) and USEPA. We have not yet received written responses to these comments. Nevertheless, we appreciate the opportunity to provide this letter to reiterate our previous concerns, and to discuss new issues arising from the PDSR.

Below are the highlights of our major concerns. More detailed comments are included in Attachment 1, attached hereto and incorporated herein by reference.

I. Shave Methodology and Arbitrary Removal of Unused RECLAIM Trading Credits (RTCs)

The District's Remaining Emissions method for calculation of RTC reductions conflicts with the CMB-01 Phase 1 and Phase 2 Control Measures as approved under the 2012 AQMP. The District's Remaining Emissions method would remove nearly all Unused RTCs from the RECLAIM market even though CMB-01 Phase 1 had explicitly considered and rejected such a reduction, instead determining that a 2 tpd reduction of Unused RTCs was more appropriate.[1] Additionally, the Incremental BARCT method proposed by the Industry RECLAIM Coalition is more consistent with Control Measure CMB-01 Phase 2 as approved under the 2012 AQMP because this method removes only those RTCs directly attributable to technology advancement (i.e., BARCT).[2]

Further, the proposed Compliance Margin of 10% may be inadequate to meet the market's historical need for Unused RTCs. Unused RTCs may be needed for several reasons, including facility-level compliance margins, which vary depending on facility size and/or risk tolerance; RTC holding requirements imposed under Rule 2005; and market liquidity, to name a few. These Unused RTCs have historically averaged in the 15-30% range (approximately 5 to 9 tpd), with the sole exception being the RTC market crisis during the 2000 compliance year. The AQMD Staff's proposal, which includes only a 10% compliance margin, appears to be inadequate for satisfying this market requirement. Hence, WSPA recommends that Staff adopt the Incremental BARCT method as their preferred proposal.

While the proposed, limited RTC adjustment account may help certain Power Sector facilities subject to Rule 2005 New Source Review (NSR) RTC holding limit requirements, it does not resolve the holding requirements applicable to many current and future non-power facilities. It is recommended that any RTC adjustment account be accessible to all RECLAIM participants subject to the Rule 2005 NSR RTC holding requirement. WSPA also recommends that Staff provide technical justification to support the quantity of RTCs set aside to fund any such adjustment account. Finally, WSPA recommends that USEPA approval of the NSR set aside concept be obtained in writing prior to adoption of the rule amendment.

II. Shave Application and Implementation Schedule

Any NOx RECLAIM shave should be applied in an equally distributed "across-the-board" manner consistent with RECLAIM founding principles[3] and the precedent set under the 2005 NOx RECLAIM shave. In addition, the proposed schedule should be consistent with the 2012 AQMP commitment to the State Implementation Plan (SIP) which was 2 tpd in the first year; anything larger may not allow sufficient time for industry to implement emission control projects necessitated by the rulemaking.[4] Since RECLAIM is tied to BARCT (as discussed in more detail below), the lack of sufficient lead time means that the proposed shave goes beyond

[1] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.
[2] SCAQMD, 2012 AQMP. Page 4-26 states: "This phase of control is to implement periodic BARCT evaluation as required under the state law." Appendix A, page IV-A-60 presents more detailed discussion for the measure.
[3] SCAQMD, Staff Report for Proposed Amended Regulation XX – RECLAIM, January 2005, Executive Summary.
[4] WSPA-SCAQMD letter, July 14, 2015.

BARCT and that RECLAIM will not achieve equivalent or greater reductions than BARCT at equivalent or lesser cost. Therefore, the shave implementation schedule should be "back-loaded" to accommodate a longer, more realistic project implementation period with at least 2 of the proposed 4 tpd (currently being proposed for 2016) being moved to 2019 or later. We are not recommending additional annual increments at this time, since the final shave amount has not been finalized.

III. Useful Life of Control Equipment

The proposed Useful Life of 25 years is inappropriate because AQMD rulemaking is far more frequent, with the prior major NOx RECLAIM rulemaking occurring only 10 years ago. Use of a 25 year assumption makes the rule costs appear lower than they actually are by diluting the significant capital costs of required projects over a much longer time table than is likely to occur. The Staff analysis should be revised to reflect the 10-year Useful Life assumption, which is more consistent with recent SCAQMD rulemaking schedules and is also consistent with the Useful Life assumption typically used by CARB and other major Air Districts.

IV. BARCT Analysis

There is a statutory requirement that RECLAIM achieve equivalent or greater emission reductions than command and control at equivalent or lesser cost.

Command and Control Regulation Would Require BARCT of the Refining Sources Subject to RECLAIM: The District is required to adopt rules and regulations implementing the AQMP.[5] Among other things, these rules and regulations must require BARCT for existing sources.[6] In rulemaking addressing existing sources outside of RECLAIM, SCAQMD is mandated to require BARCT. Because of the mandate to require BARCT on all existing sources, it is fair to say that current command and control regulations and future measures adopted as part of the plan would at least be equivalent to BARCT. In the absence of a market-based mechanism (cap-and-trade program) such as RECLAIM, SCAQMD would adopt a rule requiring source-specific BARCT for each of the sources covered under RECLAIM.

The Proposed Shave Appears to Include an Additional 5.21 Tons per Day Beyond BARCT: The proposal set forth by the District indicates that the proposed BARCT would result in a reduction of 8.79 tpd of NOx from 2011 emissions at 2000/2005 BARCT. As described above, RECLAIM must achieve emission reductions equivalent to or greater than traditional command and control, or BARCT. Thus, a NOx shave equivalent to BARCT (which the District proposes at 8.79 tpd) would be the level for comparison with the Health and Safety Code provision stating that equivalent or greater reductions would be achieved at "equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment." Yet, SCAQMD does not seek merely its determined BARCT equivalency level of 8.79 tpd; it seeks 14 tpd of NOx reductions and has not demonstrated that such reductions will be achieved at equivalent or lower cost than

[5] Health & Saf. Code § 40460.
[6] Health & Saf. Code § 40440.

BARCT. The additional 5.21 tpd reduction goes above and beyond BARCT. Such a severe reduction is not essential to compliance with the statute.

SCAQMD Needs to Demonstrate that Achieving This Additional 5.21 Tons per Day Would Be Less Costly than Achieving BARCT on a Source-by-Source Basis in the District: The Health and Safety Code requires RECLAIM to achieve at least equivalent reductions as traditional command and control at an equivalent or lesser cost.[7] While the draft staff report does provide a cost accounting for BARCT, that accounting (which we believe to be understated) only covers 8.79 tons of the 14 ton per day shave. The draft staff report does not even mention, let alone provide detailed discussion of, the costs associated with the additional 5.21 tons per day being required by the proposed rule. Because the Legislature has required RECLAIM to impose costs less than or equal to command and control regulation (i.e., BARCT), and BARCT only makes up a portion of the proposed shave, the remaining reductions which are in excess of BARCT will cost more than BARCT. The costs related solely to BARCT are substantial with refinery costs over $900 million.[8] Costs associated with the additional 5.21 tpd reduction will only increase that figure in a substantial manner. The District must include the cost figures for the additional shave amount and justify imposing these reductions under the statutory standard of achieving command and control levels at equivalent or lower costs. It is simply not reasonable to exclude such a relevant factor from consideration.

V. NEC Study

The BARCT analysis for Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[9] NEC is a third-party expert hired to confirm the Staff's technical analysis in support of this rulemaking. Following the issuance of the PDSR, however, NEC responded to SCAQMD in an August 10, 2015 letter (see Attachment 2) to "clarify the most glaring misstatements/misunderstandings of the information [NEC] provided to the District." By selectively dismissing the third-party expert's findings, without resolution of the technical issues in dispute, Staff has compromised the process and the results of that process. It is unacceptable to arbitrarily reduce the overall shave by 0.85 tpd to resolve the differences in technical assumptions. For example, if the Staff disregards the conclusion from the NEC's third-party expert report, nearly 40 operating units would be impacted by this analysis error.[10] Furthermore, any adjustment that may be justified on a technical basis should be applied to the sector where the actual BARCT reduction occurs and not to the total shave reduction (i.e., Staff's proposed adjustment of 0.85 tpd should be applied to the Refinery Sector's BARCT reduction).

While WSPA understands that BARCT should represent a level of performance that is technically feasible and cost-effective for most units on a retrofit basis in a given source category, the District's assumptions regarding the feasibility of achieving the BARCT levels are

[7] Health & Saf. Code § 39616(c)(7).
[8] SCAQMD, *Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM* (Draft NOx RECLAIM Staff Report), p. 23. (July 21, 2015)
[9] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[10] SCAQMD, Preliminary Analysis – Refinery Boilers/Heaters, July 2014 (posted on AQMD website October 2014).

not supported by evidence that the units in question can achieve 2 ppm NOx. In fact, the data provided by Staff (Appendix B of the PDSR) indicates that only 4 of the 76 installed SCRs in the boiler and heater category are currently performing below 2 ppm. This alone suggests that the proposed BARCT is not representative. Even more, in a confidential WSPA refinery survey,[11] conducted by a third party contractor, only 2 of the 4 are retrofits. This does not represent the necessary proportion of the units in this source category.

The draft staff report proposes 2015 BARCT levels of 2 ppmv of NOx for FCCUs, refinery heaters and boilers greater than 40 mmbtu/hr, gas turbines, and sulfur recovery unit tail gas incinerators. While the District justifies these levels based on an assumption that all refinery equipment can reach such levels, the draft staff report says otherwise. With respect to refinery heaters and boilers, very few of the existing refinery heaters and boilers already equipped with SCR are able to meet 2 ppmv of NOx. In fact, as stated in the draft staff report, of the 212 refinery boilers and heaters classified as major and large NOx sources, 14 heaters using refinery fuel gas have achieved 1.6-3.5 ppmv NOx, two boilers using natural gas have achieved 2-5 ppmv NOx, and a crude heater using refinery fuel gas achieved 3-8 ppmv NOx. Apart from some unknown percentage of the 14 process heaters, none of these sources already employing the control technology on which the BARCT level is based (SCR) have shown an ability to reduce emissions below 2 ppmv NOx. Accordingly, the District has not shown that a BARCT level of 2 ppmv NOx is achievable over the broad spectrum of refinery heaters and boilers subject to the proposed amendments. Therefore, 5 ppm is a more appropriate endpoint for refinery boilers/heaters.

The same is true with respect to FCCUs. The District proposes a 2015 BARCT level of 2 ppm NOx based on the ability of one FCCU achieving the proposed level. As explained by the District's consultant, of the three FCCUs currently operating with SCRs, only one of them achieves less than 2 ppmv NOx.[12] Again, achievability in one unit does not guarantee similar performance in other units, particularly units that have been operating under different conditions for many years. Each refinery has unique circumstances such as equipment type, age, and configuration that factor into its ability to achieve the proposed emission levels. Thus, what may be achievable for one piece of equipment may not be for another. Further, while there may be controls available with the ability to achieve the proposed level of performance, such control may come at a cost that is unreasonable. The District has not shown that the proposed levels can be achieved across the board in a cost effective manner. As a result, and to be consistent with the statutory obligations, the District needs to reconsider and revise the proposed BARCT levels to ensure that they are achievable by a more representative percentage of the sources subject thereto.

VI. Costs and Cost Effectiveness

Exclusion of the NEC cost estimates results in an inappropriate minimization of the estimated Refinery Sector costs presented in the PDSR. It also inflates the presented emission reductions estimate for the Refinery Sector. The BARCT analysis should be revised to explicitly reflect the

[11] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.
[12] Norton Engineering, *Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM-SCRs for FCCUs Document No. 14-045-7* (August 10, 2015).

NEC cost estimates for Refinery Sector categories. Additionally, use of the Discounted Cash Flow (DCF) method along with interest rate and useful life assumptions make estimated costs for this rulemaking appear less expensive than they would be under the Levelized Cash Flow (LCF) method used by CARB and most other major Air Districts. WSPA believes that the LCF method is a better representation of cost effectiveness than the DCF method and recommends it be used. The same cost effectiveness threshold should be used for both DCF and LCF methods. Staff has used a higher cost threshold for LCF in the past than they used for DCF, so that the differences between the two methods are diluted.

The proposed $50,000 cost effectiveness threshold is greater than the AQMD's DCF cost effectiveness threshold for Command-and-Control sources in South Coast. Under the 2012 AQMP, the approved cost threshold for NOx control measures was $22,500 per ton,[13] and AQMD's current Best Available Control Technology (BACT) guidance document presents a cost effectiveness threshold that is only $19,100 per ton.[14] Also, the Health & Safety Code requires that market-based program costs be "equivalent or less compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment" and "the program will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment." [H&SC 39616(c)(1) and (7)]. Staff has not demonstrated that these legal obligations are satisfied. Therefore, WSPA recommends that the PDSR analysis be revised with the cost effectiveness threshold not greater than $22,500 (i.e., the cost effectiveness threshold used in the 2012 AQMP).

Further, the draft staff report understates the actual costs associated with meeting the proposed BARCT levels. As the District has done in past rulemakings, it hired NEC to provide reviews and recommendations on the analysis developed by SCAQMD as it relates to the technical feasibility of the control options as well as the cost effectiveness of each option. After gathering information from onsite visits to six of the refineries, NEC provided the District with a comprehensive evaluation of costs of each control option, the size and space needed for the equipment, and the time needed to install the control technologies. The District, however, chose to use different cost estimation approaches, opting to selectively disregard its own consultant's evaluation. This information was site specific and should be considered more credible than the District's generic evaluation of costs. It is a hallmark of reasoned decision-making that an agency use the most accurate available information.

Apart from WSPA's concern relating to the dismissal of NEC's evaluation, the District's estimates do not include all of the costs that are required to be considered, and therefore vastly understate the cost impacts of the BARCT proposed. It appears that installation, design, and engineering costs have not been included properly. Moreover, it is critical to recognize that each refinery is unique such that BARCT levels achievable and cost effective at one refinery may not be at another. Plant configuration, equipment type, equipment age, length of time the SCR must remain in service and consistently achieving emission reduction targets between maintenance opportunities (most FCCUs, heaters, and boilers operate for years at a time, 24 hours per day and

[13] SCAQMD, 2012 AQMP, December 2012, pages 4-43.
[14] SCAQMD, BACT Guidelines, Part C: Policy and Procedures for Non-Major Polluting Facilities, 2006.

7 days per week), and composition of fuel, are a few of the factors in play with determining the costs associated with achieving the proposed levels. For example, some refinery configurations such as processes that utilize dual stacks, may require more than one SCR, and thus greater expenditures (i.e., double), to achieve the proposed level. It does not appear that such a scenario was considered by the District in developing its cost effectiveness determinations.

Accordingly, WSPA believes that the District's cost effectiveness calculations significantly understate the costs associated with achieving the proposed BARCT levels. We believe that even the Norton analysis underestimates actual costs. WSPA is currently developing additional information based on detailed engineering assessments that more accurately represent the costs associated with the proposed BARCT. We will submit this information to the record as it becomes available.

VII. Disproportionate Impacts

Under Health and Safety Code Section 39616(c)(7), the District must show that RECLAIM facilities are not being disproportionately impacted by participating in the program.[15] The draft staff report, noting the emission projections described in the 2012 AQMP, indicates that RECLAIM sources make up 37 percent of the projected NOx emissions for 2023 from stationary sources.[16] Table 2.1 of the draft staff report indicates that non-RECLAIM sources, including waste disposal and miscellaneous processes, will account for 46 tons per day of the annual average NOx emissions for the 2023 base year while RECLAIM sources (pre-shave) will account for 27 tons per day.[17]

In its proposal, the District is seeking substantial reductions from RECLAIM sources, the majority of which come from the nine refineries in the Basin. Nonetheless, there is nothing in the draft staff report or other proposal document that indicates what reductions will be required for non-RECLAIM facilities. In fact, there is no evidence presented that would lead the Board to make a finding that RECLAIM facilities are not taking the brunt of the load when it comes to requiring emission reductions. The District has failed to provide "appropriate information" to "substantiate" a finding of no disproportionate impact.

Indeed, for the Board to make such a finding, there must be evidence indicating that non-RECLAIM facilities are, on an aggregate basis, required to reduce their NOx emissions at the levels required by their RECLAIM counterparts (at least proportionately). Non-RECLAIM facilities represent the majority of the stationary NOx emissions, yet SCAQMD appears to be seeking *no* reductions from such sources. Barring appropriate information showing that non-RECLAIM sources are required to reduce emissions equivalent to what is proposed by these amendments, the Board cannot make the required findings and as a result, the proposed amendments violate the District's statutory mandate.

[15] Health & Saf. Code § 39616(c)(7).
[16] SCAQMD, *Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM* (Draft NOx RECLAIM Staff Report), p. 14. (July 21, 2015)
[17] *Id.*

VIII. Energy Efficiency Projects

Staff suggests that there are NOx emission co-benefits available from Refinery Sector sources due to energy efficiency projects that are in addition to the projected emission reductions under this rule. This is essentially an erroneous assumption due to the fact that the AQMD is relying on information that was submitted under the California AB32 Energy Efficiency and Co-Benefits regulation and most of the projects that were presented by Refinery Sector facilities in those 2011 vintage reports were already completed. As such, those emissions benefits were already reflected in the 2011 baseline year emissions presented in the PDSR. AQMD Staff acknowledges as much in PDSR Table 3.2. As such, these co-benefit reductions should not be presented or characterized as a potential additional benefit.

IX. Socioeconomic Impacts

Under Health and Safety Code Section 40728.5, the District is required to perform an analysis of the socioeconomic impacts of the proposed regulation. This assessment is important because it lays out the range of probable economic impacts to the regulated industries as well as the impact on the economy of the region as a whole. Unfortunately, the socioeconomic impacts analysis is not available at this time. WSPA believes that reviewing the analysis is important to its ability to meaningfully comment on these proposed regulatory changes. Accordingly, WSPA may change or supplement its comments on review of the analysis when it is released.

Thank you for considering the comments addressed in this letter. We look forward to continuing to work with you and your Staff on this important rulemaking. WSPA reserves the right to file additional comments or other materials as this rulemaking progresses.

Sincerely,

Suzanne E. Gornick

cc: Dr. Barry Wallerstein
Joe Casmassi

Attachment 1

ATTACHMENT 1

ADDITIONAL COMMENTS ON PRELIMINARY DRAFT STAFF REPORT (PDSR) FOR NO_X RECLAIM AMENDMENTS

Page/Section	WSPA Comment
Page 2, Current Emissions and RTC Holdings.	AQMD should use 2012 compliance year emissions as the baseline year for "current emissions" for all industrial sectors. WSPA understands the rationale presented by AQMD for use of 2012 data to characterize baseline Power Sector emissions. However, non-Power RECLAIM facilities were also exhibiting lower output levels in 2011 due to the recession that started in 2007. This is shown in attached Figure 1. Looking at certain key industrial sectors yields a similar conclusion. On a sectoral level, publicly reported economic data (see Figure 2A and Figure 2B) shows that economic output and emissions for the cement and textile manufacturing sectors in AQMD were also still recovering from recessionary low points in 2011. For these reasons, WSPA recommends that AQMD revise the Staff Report to use 2012 compliance year emissions as the baseline emissions year for all industrial sectors.
Page 3: Table EX-1, Summary of Proposed BARCT (May 2015).	Table EX-1 presents data for the Refinery Sector which fails to reflect changes necessitated by the findings of the third-party expert hired to confirm the AQMD Staff's Refinery Sector technical analysis for this rulemaking. The Staff's BARCT analysis for the Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[1] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. We also note that NEC has raised a significant number of technical issues with the conclusions presented in the PSDR for the Refinery Sector categories.[2] WSPA strongly suggests that these technical issues be resolved before further presentation of emissions reductions attributable to the proposed BARCT analysis.
Page 3. Last paragraph, 3rd sentence. Resolution of Uncertainties	WSPA recommends this section be re-written after the requested and required changes to the Staff's BARCT analysis have been completed. The subject paragraph suggests that Staff has "accounted for uncertainties that arose in the BARCT analysis…." We disagree. There continues to be a significant number of unresolved issues which result in uncertainty in the Staff analysis presented in the PDSR. This includes, but is not limited to the Staff's decision to selectively ignore the findings of the agreed upon third-party expert for the Refinery Sector.

[1] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[2] James Norton, NEC, letter to Dr. Philip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

Page 3. Last paragraph, 3rd sentence. Proposed Adjustment Account	The proposed "Adjustment Account" should be accessible by all RECLAIM facilities subjected to the Rule 2005 NSR RTC holding requirement. Furthermore, AQMD Staff should provide a technical rationale to support the quantity of RTCs set aside to fund any such adjustment account. The PDSR suggests the RTC demand caused by Rule 2005 RTC holding requirements are addressed by the proposed creation of an RTC Adjustment Account for power plants. However, the RTC holding requirements imposed under Rule 2005 are also applicable to many non-Power Sector facilities under RECLAIM New Source Review. The Staff's current proposal does nothing to address the RTC demand associated with these non-Power Sector facilities. This should be resolved.
Page 3. Last paragraph, 3rd sentence. Proposed Adjustment Account	AQMD Staff should provide a regulatory discussion detailing how this proposed Adjustment Account would be managed, and how RTCs in the account would be treated with respect the to the State Implementation Plan (SIP).
Page 3. Last paragraph, 5th sentence. Compliance Margin	WSPA recommends this section be re-written to eliminate potential misstatements concerning the level of "unused RTCs" that might be available under the Staff's proposed shave. The Staff's "Remaining Emissions" approach as presented in the PDSR limits the overall "Compliance Margin" for RECLAIM facilities to 10% of projected 2023 emissions (i.e., not 23%). The Staff's Remaining Emissions estimate excludes some RECLAIM market sectors (i.e., cement) which had reduced emissions in 2011 due to the major recession from which certain sectors were still recovering. Staff has made an adjustment to account for that omission, but this paragraph then suggests that such adjustment is part of the overall market's Compliance Margin. That is incorrect.
Page 4: 1st full paragraph. Application of Shave	The proposed NOx RECLAIM shave should be applied in an equally distributed, "Across the Board" manner consistent with RECLAIM founding principles and the precedent set under the 2005 NOx RECLAIM shave. RECLAIM is a market-based program which was designed to use "the power of the marketplace"[3] to reduce air emissions from stationary sources. This approach was expressly intended not to impose "command-and-control" requirements on specific facilities or specific equipment therein. Rather, RECLAIM was intended to provide Southern California businesses with greater flexibility and a financial incentive to reduce air pollution at least equal to what traditional command-and-control rules would have required. This program has been very successful in reducing NOx emissions with RECLAIM facilities having reduced their overall actual emissions well in excess of the program's current target under Regulation XX.

[3] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim.

	The District has previously considered and rejected targeted shaves as noted in the excerpts below: • Oct 1993, RECLAIM Program Summary: "Throughout the development of RECLAIM, the District evaluated several design options that would have treated some industries differently than others……After evaluating advantages and disadvantages, the District adopted a program that treats all sources consistently for equity and fairness." • 2005 Staff Report, Appendix E: "The Staff proposal is taking the "across-the-board" reduction of NOx RTC holdings approach by looking at the total reductions possible based on BARCT determinations and reducing allocations for all RTC holders by the same percentage…This approach, from a market design standpoint and based on the overall conceptual design of the RECLAIM program to achieve programmatic BARCT, is the most equitable…" The Staff proposal presented in the PDSR is inconsistent with the founding principles of the RECLAIM program that stressed the importance of a market-based program, as well as the precedent established by the SCAQMD in previous NOx regulatory reductions in 1999 and 2005. An equally distributed "across-the board" treatment of all sources, as originally designed and implemented since the program's inception in 1994, is critical to the continued success of the RECLAIM program.
Page 4: 1st full paragraph, 3rd sentence. Small Facilities	This sentence states "The remaining 210 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was no new BARCT for the types of equipment and operation at these facilities." This statement is factually incorrect and should be corrected. AQMD Staff opted not to review BARCT for these facilities under this RECLAIM rulemaking. Additionally, AQMD and other California air districts have previously made BARCT determinations that would apply to the equipment and operations at those smaller emitting facilities (e.g., boilers, heaters, etc.) were they not under RECLAIM.[4]
Page 4: 2nd and 3rd full paragraphs. Implementation Schedule	The proposed Implementation Schedule should be revised to shave not more than 2 tons per day (tpd) from the program in the first year. This is consistent with Governing Board's direction under Control Measure CMB-01 Phase 1. Additionally, the overall schedule should be longer than the proposed seven (7) years to ensure RECLAIM facilities have sufficient time to comply. 2012 Air Quality Management Plan (AQMP) Control Measure CMB-01) Phase 1 was approved by the Governing Board on the basis that 2 tpd would be removed from RECLAIM in the event of the $PM_{2.5}$ contingency measure being triggered.[5] The proposed schedule should be consistent with that 2 tpd State Implementation Plan (SIP) commitment; anything

[4] See SCAQMD Regulation XI for examples.
[5] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.

	larger may not allow sufficient time for industry to implement emission control projects necessitated by the rulemaking. Also, the proposed schedule for full implementation by 2022 may be insufficient to achieve the proposed level of NOx emission reductions from RECLAIM facilities. Refinery Sector sources may need 8 years or more to fully engineer, permit, construct and operationalize all the projects needed to comply with the proposed rulemaking.[6]
Page 6: Table EX-2, Summary of Public Process.	To provide ample opportunity for stakeholder review and comment, AQMD Staff should revise this schedule to provide the public with a realistic schedule for this rulemaking that includes the CEQA Program Environmental Assessment (PEA) and the Socioeconomic Analysis.
Page 19: Co-Benefits of Energy Efficiency Projects.	This section should be completely removed from the PDSR or significantly revised to correct factual mischaracterizations. The information submitted by refineries to the California Air Resources Board in 2011 under the AB32 Energy Efficiency and Co-Benefits regulation reflected projects that mostly had been completed by 2011. Thus, those co-benefits were already reflected in the 2011 baseline year emissions presented in the PDSR and cannot be characterized as additional or creditable. Staff have acknowledged as much in PDSR Table 3.2.
Page 29 CEQA Alternatives	The size of the shave approved in the 2012 AQMP should be included in the list of CEQA alternatives.
Chapter 4: Costs and Cost Effectiveness. Cost Thresholds	The cost effectiveness threshold for this rulemaking should not be greater than $22,500 (i.e., the cost effectiveness threshold used in the 2012 AQMP) and the BARCT analysis presented in the PDSR should be revised accordingly. The $50,000 cost effectiveness threshold proposed by AQMD Staff is greater than the AQMD's DCF cost effectiveness threshold for Command-and-Control sources in South Coast. Under the 2012 AQMP, the approved cost threshold for NOx control measures was $22,500 per ton. As an additional data point, AQMD's current Best Available Control Technology (BACT) guidance document presents a DCF cost effectiveness threshold of only $19,100 per ton. Health & Safety Code (H&SC) §39616(c) requires that market-based program costs will be "equivalent or less compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment" and also requires "the program will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment."[7] The AQMD Staff analysis presented in the PDSR has not demonstrated that these obligations are satisfied.
Chapter 4: Costs and Cost Effectiveness.	A 10-year "Useful Life" assumption is more appropriate given actual rulemaking timetables; the BARCT analysis presented in the PDSR should be accordingly revised to use a 10-year Useful Life assumption.

[6] Stillwater Associates LLC, RECLAIM Analysis for WSPA, July 2015.
[7] Health & Safety Code §39616(c)(1) and (7).

Useful Life Assumption	The AQMD Staff's proposed 25-year Useful Life is inappropriate because AQMD rulemaking occurs on a far more frequent recurrence. The last major NOx RECLAIM rulemaking was only 10-years ago. Use of a 25-year assumption makes the rule costs appear lower than actual by diluting the significant capital costs of required projects over a much longer time table than is likely to occur. The AQMD Staff analysis should be revised to reflect the 10-year Useful Life assumption which is more consistent with recent AQMD rulemaking schedules and is also consistent with the Useful Life assumption typically used by CARB and other major Air Districts.
Chapter 4: Costs and Cost Effectiveness. DCF Method	The BARCT analysis presented in the PDSR should be revised to utilize the Levelized Cash Flow (LCF) methodology used by CARB and other major air districts. Use of the DCF method, in combination with the proposed interest rate and Useful Life assumptions serves to distort the estimated costs for this AQMD rule by making them appear less expensive than they would be using the Levelized Cash Flow (LCF) method employed by CARB and other major Air Districts. The same threshold should be used for both DCF and LCF.
Chapter 5: RTC Reductions, Remaining Emissions Remaining Emissions Method	The AQMD Staff's "Remaining Emissions" method conflicts with Control Measure CMB-1 Phase 1 as approved under the 2012 AQMP and should be replaced with the Incremental BARCT method proposed by the Industry RECLAIM Coalition. The Remaining Emissions method presented in the PDSR conflicts with Control Measure CMB-1 Phase 1 because it would remove nearly all Unused RTCs (i.e., "surplus") from RECLAIM. CMB-01 Phase 1 explicitly considered and rejected such a reduction; instead arguing that a 2 tpd of reduction for Unused RTCs was more appropriate due to concerns that baseline RECLAIM emissions might reflect the economic downturn.[8] As noted above, many Southern California industry sectors covered by RECLAIM were in fact still under a recessionary hangover in 2011 so such concerns were valid. Furthermore, the "Incremental BARCT" method is more consistent with Control Measure CMB-1 Phase 2 approved under the 2012 AQMP [9] because the method would only remove RTCs in an amount attributable to technology advancement (i.e., BARCT). AQMD Staff's own analysis demonstrates that less than 9 tpd of proposed RTC reductions are attributable to the 2015 BARCT analysis. Yet the Staff proposal proposes to shave 14 tpd. Removing RTCs beyond what is supported by technology advancement may subject facilities in the RECLAIM program to disproportionate impacts, measured on an aggregate basis, compared to other permitted stationary sources in the District's plan for attainment. It may also subject

[8] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.
[9] SCAQMD, 2012 AQMP. Page 4-26 states: "This phase of control is to implement periodic BARCT evaluation as required under the state law." Appendix A, page IV-A-60 presents more detailed discussion for the measure.

	RECLAIM facilities to greater costs compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment. Either of these outcomes would conflict with H&SC 39616(c). AQMD has not demonstrated that the Staff proposal successfully meets these obligations. Further, under Section 40727, the Legislature has established that regulations must meet the requirements of necessity, authority, clarity, consistency, non-duplication, and reference. The necessity requirement ensures in part that unnecessary costs are not imposed on the economy of California. Accordingly, the District needs to establish that the shave is no more stringent than what is "necessary." Necessity "means that a need exists for the regulation, or for its amendment or repeal, as demonstrated by the record of the rulemaking authority."[10] Through the 2012 AQMP, SCAQMD has described that a need exists for a reduction in NOx emissions. The ceiling of that need was five tons per day. The magnitude of the current shave proposal goes above and beyond what is necessary to meet the requirements of the AQMP or any other statutory or regulatory obligation that SCAQMD faces.

Chapter 5: RTC Reductions, Remaining Emissions Compliance Margin	The proposed Compliance Margin of 10% appears inadequate to meet the market's historical need for Unused RTCs and should be revised to the 20-30% range. The RECLAIM market has exhibited "Unused RTCs" since program inception. This may be for several reasons including facility compliance margins which range in size depending on facility size and/or risk tolerance, RTC holding requirements imposed under Rule 2005, or market trading to name few. These Unused RTCs have historically averaged in the 15-30% range (5 to 9 tpd) with the sole exception being the market crisis during the 2000 compliance year.[11] The AQMD Staff's proposal (with only 10% compliance margin) may be inadequate for satisfying this market requirement. Excessive shaving of Unused RTCs could result in a market which is unable to accommodate the economic activity levels projected in the Staff's analysis. Furthermore, removal of all Unused RTCs would directly conflict with Control Measure CMB-01 Phase 1 as authorized by the Governing Board.
Chapter 5: RTC Reductions, Remaining Emissions Table 5.1 – Remaining Emissions for Refinery Sector (May 2015)	The BARCT analysis for the Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review, and Table 5.1 should be accordingly revised. As noted in the PDSR, the Staff analysis fails to account for the technical recommendations from NEC, the third-party Refinery Sector expert hired by the AQMD. NEC's findings have material impacts on the resulting BARCT determinations for certain Refinery Sector categories. Once corrected, the projected "2023 Remaining Emissions at 2015 BARCT" for the Refinery Sector will increase, and the "2023 Emission Reductions Beyond 2000/2005 BARCT" will decrease. These technical corrections are critical to a fair application of the proposed shave.

[10] Health & Saf. Code § 40727.
[11] SCAQMD, Annual RECLAIM Audit Report for 2013 Compliance Year, 6 March 2015. See Table 3-2.

Appendix A - Refinery Fluid Catalytic Cracking Units (FCCUs) Page 53. Incremental Costs and Cost Effectiveness Cost Effectiveness Calculations	The cost effectiveness analysis presented for FCCUs in Appendix A does not consider the 2000/2005 BARCT emissions or cost baselines. This conflicts with the methodology outlined in Chapter 4. The Staff BARCT analysis should be accordingly revised based on the incremental cost effectiveness approach outlined in Chapter 4. Staff proposes that the cost effectiveness of 2015 BARCT is to be calculated based on the incremental cost of progressing from 2000/2005 BARCT to the proposed 2015 BARCT level, divided by the incremental emissions benefit related to the progression from 2000/2005 BARCT to the proposed 2015 BARCT level (i.e., "2023 Emission Reductions Beyond 2000/2005 BARCT"). For some reason, it was not applied in this manner for the FCCUs. We request that this oversight be corrected.

Appendix A - Refinery Fluid Catalytic Cracking Units (FCCUs) Page 53. Incremental Costs and Cost Effectiveness Consideration of Third-Party Expert's Recommendations on Cost	The Staff's BARCT analysis for the Refinery FCCUs category should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[12] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings, without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. We also note that NEC has raised a significant number of technical issues with the conclusions presented in the PSDR for the Refinery FCCUs which have reportedly been discussed with Staff and were reiterated in NEC's letter dated 10 August 2015.[13] Norton's comments are attached hereto and incorporated herein by reference. These technical issues are significant and should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis.
Appendix B – Refinery Boilers and Process Heaters Page 60, Achieved-In-Practice NOx Levels for Boilers and Heaters Proposed BARCT	WSPA requests further technical demonstration to support the proposed BARCT level for refinery heaters and boilers; the proposed BARCT level does not appear to represent an achievable level of performance for most refinery heaters/boilers operating on refinery fuel gas. According to the AQMD's figures, fewer than 10% of the heater/boiler units already equipped with SCR technology are able to achieve the proposed BARCT level. This does not suggest the performance level can be broadly achieved with add-on emissions controls. If this level of performance effectively demands basic equipment replacement, the AQMD's BARCT analysis should identify and quantify costs for that demand. WSPA also requests clarification on the number of refinery heaters and boilers reported to that have "very low emissions levels." AQMD Staff have provided conflicting counts to stakeholders, and those counts conflict

[12] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[13] James Norton, NEC, letter to Dr. Philip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

	with information provided to WSPA directly by WSPA member refineries.[14] The PDSR reports fourteen refinery heaters in the AQMD as using refinery fuel gas and achieving NOx concentrations "between 1.6 and 3.5 ppmv" (corrected to 3% O2) using Selective Catalytic Reduction (SCR) technology. AQMD Staff also report that two boilers have achieved NOx emissions between 2 and 5 ppmv using LoTOx scrubbers and natural gas. We understand that AQMD's analysis is based on data collected from Southern California refineries under a 2013 survey.[15] AQMD had previously reported to the RECLAIM Working Group that, based on that same survey, only nine refinery heaters/boilers were achieving below 5 ppmv. WSPA requests clarification on how this count of units with "very low emissions levels" could have changed. Lastly, AQMD should not categorize units between performing "between 1.6 and 3.5 ppmv" as a single group consistent with the proposed BARCT. 3.5 ppmv does not equal 2 ppmv, and some units which achieve 3.5 ppmv may be unable to meet 2 ppmv even with add-on controls. We would suggest this group supports a BARCT determination of 3.5 ppmv; not 2 ppmv.
Appendix B – Refinery Boilers and Process Heaters Page 60, Achieved-In-Practice NOx Levels for Boilers and Heaters Cost Basis for BARCT and Consideration of Third-Party Expert's Recommendations on Cost	The Staff's BARCT analysis for the Refinery heaters and boilers should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review, and any subsequent comments from NEC.[16] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. The AQMD Staff's analysis suggests that the proposed BARCT level of 2 ppmv can be achieved with less equipment (e.g., 1 layer of catalyst) and less cost than suggested by the third-party Refinery expect; a firm that engineers such equipment as its primary business. Counter to the AQMD Staff's assertion that NEC was simply wrong on its design basis is the fact (reported by AQMD)[17] that fewer than 10% of the existing Refinery heaters/boilers with SCR technology are able to meet 2 ppmv. This result includes both new and retrofit installations and suggests that the proposed 2 ppmv NOx performance level may not be as easily achieved as suggested by Staff. Given the material impact of these technical issues on the BARCT analysis, they should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis. Specifically, we request that the BARCT analysis presented in Appendix B be revised to consider the cost estimates presented by NEC.
Appendix B – Refinery	The BARCT cost effectiveness analysis presented in this table suggests

[14] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, Mar 2015.
[15] SCAQMD, Preliminary Draft Staff Report (PDSR) for Proposed Amendments to NOx RECLAIM, 21 July 2015.
[16] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[17] SCAQMD, NOX RECLAIM Working Group Meeting, 19 September 2013.

Boilers and Process Heaters Table B.11 - Details of Cost Estimates for Boilers and Heaters (March 2015)	AQMD Staff have selectively applied the methodology outlined in Chapter 4. This is specifically a problem for select heaters which are reportedly already meeting proposed BARCT. In these instances, Staff has claimed emissions reductions relative to the 2000/2005 BARCT level without assigning any programmatic costs for those reductions. This is inconsistent with the programmatic approach outlined in Chapter 4, under which cost effectiveness of 2015 BARCT is to be calculated based on the incremental cost of progressing from a 2000/2005 BARCT level to the proposed 2015 BARCT level, divided by the incremental emissions benefit related to the progression from 2000/2005 BARCT to the proposed 2015 BARCT level (i.e., "2023 Emission Reductions Beyond 2000/2005 BARCT"). WSPA does not believe it appropriate for Staff to selectively "pick and choose" when use the prescribed programmatic approach. The Staff BARCT analysis should be revised accordingly to be fully consistent with the incremental cost effectiveness approach outlined in Chapter 4.
Appendix D - Coke Calciner Staff's Recommendation	WSPA appreciates that AQMD Staff accepted NEC's recommended BARCT level of 10 ppmv and has incorporated it into the BARCT analysis for this source category.
Appendix E - Sulfur Recovery Units/Tail Gas Incinerators Page 110. Costs and Cost Effectiveness Design Basis for BARCT and Consideration of Third-Party Expert's Recommendations	The Staff's BARCT analysis for the Refinery Sulfur Recovery Units/Tail Gas Incinerators (SRU/TG Incinerators) category should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[18] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. As with other categories, the AQMD Staff's analysis suggests that the proposed BARCT level of 2 ppmv can be achieved for SRU/TG Incinerators with less equipment (e.g., fewer layers of catalyst) and less cost than suggested by the third-party Refinery expert; a firm that engineers such equipment as its primary business. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. Given the impact of these technical issues on the projected emissions and costs for this category, these issues should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis. Specifically, we request that the BARCT analysis presented in Appendix E be revised to consider the cost estimates presented by NEC. Tables E.1 and E.2 should include NOx concentration levels.
Appendix K – Co-Benefits of Energy Efficiency Projects	This appendix should be completely removed from the PDSR or significantly revised to correct factual mischaracterizations.

[18] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

	The information submitted by refineries to the California Air Resources Board in 2011 under the AB32 Energy Efficiency and Co-Benefits Regulation reflected projects that had mostly been completed by 2011. Thus, those co-benefits were already reflected in the 2011 baseline year emissions presented in the PDSR and cannot be characterized as additional or creditable. Staff have acknowledged as much in Table K.1 and also PDSR Table 3.2.

Part III – RTC Reduction Approaches Appendix U – Staff's Proposal and CEQA Alternatives	The proposed NOx RECLAIM shave should be applied in an equally distributed, "Across the Board" manner consistent with RECLAIM founding principles and the precedent set under the 2005 NOx RECLAIM shave. RECLAIM is a market-based program which was designed to use "the power of the marketplace"[19] to reduce air emissions from stationary sources. This approach was expressly intended not to impose "command-and-control" requirements on specific facilities or specific equipment therein. Rather, RECLAIM was intended to provide Southern California businesses with greater flexibility and a financial incentive to reduce air pollution at least equal to what traditional command-and-control rules would have required. This program has been very successful in reducing NOx emissions with RECLAIM facilities having reduced their overall actual emissions well in excess of the program's current target under Regulation XX. The District has previously considered and rejected targeted shaves as noted in the excerpts below: • Oct 1993, RECLAIM Program Summary: "Throughout the development of RECLAIM, the District evaluated several design options that would have treated some industries differently than others……After evaluating advantages and disadvantages, the District adopted a program that treats all sources consistently for equity and fairness." • 2005 Staff Report, Appendix E: "The Staff proposal is taking the "across-the-board" reduction of NOx RTC holdings approach by looking at the total reductions possible based on BARCT determinations and reducing allocations for all RTC holders by the same percentage…This approach, from a market design standpoint and based on the overall conceptual design of the RECLAIM program to achieve programmatic BARCT, is the most equitable…" The Staff proposal presented in the PDSR is inconsistent with the founding principles of the RECLAIM program that stressed the importance of a market-based program, as well as the precedent established by the SCAQMD in previous NOx regulatory reductions in 1999 and 2005. An equally distributed "across-the board" treatment of all sources, as originally designed and implemented since the program's inception in

[19] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim.

	1994, is critical to the continued success of the RECLAIM program.

SUPPORTING FIGURES

Figure 1. **U.S. Excluding California, California Excluding SCAQMD, and SCAQMD Output Index, All Regulated Industries Combined, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)**

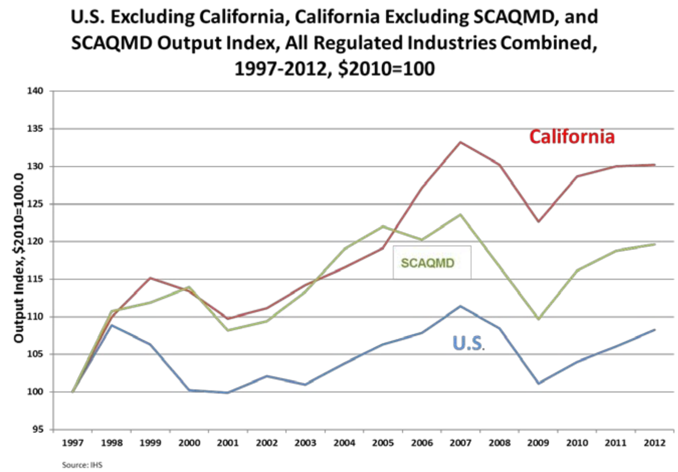


Figure 2A. **South Coast AQMD Region Cement Output and Emissions, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)**

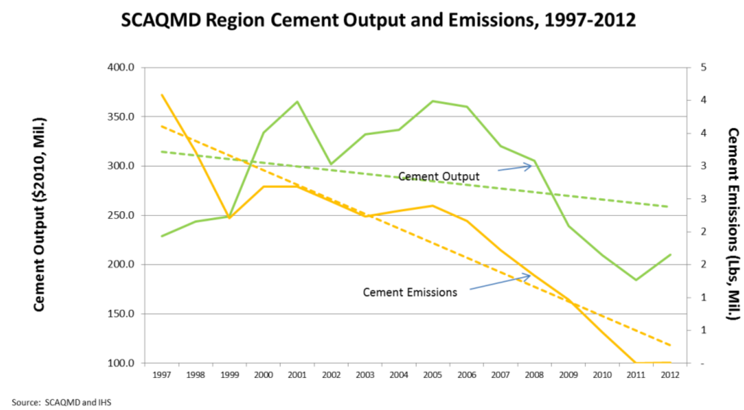
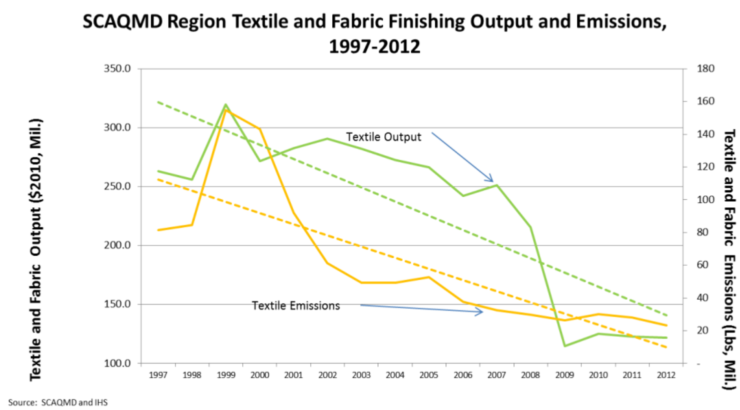


Figure 2B. South Coast AQMD Region Textile and Fabric Finishing Output and Emissions, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)



Attachment 2

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August 10, 2015

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Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for FCCUs
Document No. 14-045-7

Dear Mr. Fine,

We have completed a first pass review of the above captioned report's discussion of SCR applications to district SCRs and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on FCCU SCR Costs

Appendix F presents a review of NEC's analysis for FCCU SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommends using three catalyst beds and designing for superficial gas velocities of 10 ft/sec vs SCR vendor proposals which have less catalyst and 20% higher superficial velocities.
- NEC conditions budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment. This is characterized by staff as: "Adding a "mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs".
- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: "Adding another 75% increase in labor to the costs of the manufacturer's SCR.".
- NEC used incorrect FCCU feed rates in developing comparisons to AQMD PWVs.

The following paragraphs address each of staff's objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report.

**Basis for Catalyst Addition and
Velocity Reductions vs Vendor Budget Quotes**

All FCCU SCR catalyst beds are in the range of 3 - 4' deep, all are prone to plugging by catalyst and/or ABS and all have limitations on allowable pressure drop, so superficial velocity is a good basis for comparison between units. The district has three operating FCCU SCRs. All units have two catalyst beds and operate at superficial gas velocities in the range of 8 to 13 ft/sec. Two of the three units, operating at superficial velocities of 12 and 13 ft/sec do not achieve emissions of 2 vppm @ 3% O_2. The other unit, highlighted in the draft report, achieves less than 2 vppm @ 3% O_2 operating at a superficial velocity of 7.7 ft/sec. The "good" unit is operating with inlet NOx levels which are 50%

of design or lower and at lower than design flue gas flows. There are several ways to bring the two "non-performing" units into compliance with the revised standard, each with different costs and different overall performance impacts. NEC was not commissioned to do an evaluation of individual units and propose improvement options, but rather to make an assessment of what it would take, cost wise, to reliably achieve the 2 ppmv limit for grass roots SCR installations. Based on the experience of operating units in the district, and our direct experience with FCCU units for other clients (due to confidentiality agreements we cannot divulge client identities and specific locations) reliably achieving 2 vppm NOx emissions in an FCCU over a five year run will require the addition of catalyst and will be designed for superficial velocities of 10 ft/sec or less. Considering that SCR catalyst vendors have not developed and guaranteed a specific SCR design for 2 ppmvd @ 3% O_2 NEC feels that it is prudent to assume that a third bed of catalyst (SCR or ASC) and cross section designed to achieve a maximum superficial velocity of 10 ft/sec is sufficient to characterize the most likely cost of a SCR unit capable of achieving 2 ppmvd in a typical refinery FCCU environment. *The impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation has been overstated by district staff as a 284% increase in catalyst volume over manufacturer's estimates. The increase over manufacturer's budget estimates/proposals is actually 92%, one half of staff's reported delta.*

Staff's SCR Design Comparison Did Not Accurately Reflect NEC's "Typical" FCCU SCR Design

Staff used an incorrect basis for comparing NEC's typical FCCU SCR with district units in Table F.3. A revised comparison, using data from Refineries 1, 5 and 6 is shown below.

Table 1 (F. 3 Showing NEC Typical SCR)
Performance Information of Existing SCRs

	Refinery 1	Refinery 5	Refinery 6	NEC Typical
FCC Feed Rate, kBPD	95	71	84	55
SCR Inlet Flue Gas Flow, ACFS	6,585	5,525	9,685	3,848
SCR Manufacturer	1	3	2	--
No. Catalyst Layers	2	2	2	3
Catalyst Volume, ft^3	6,200	2,975(1)	6,200(5)	4,600
Design Inlet NOx, ppmv	133(2)/40-80(3)	150	35	45
Design Outlet NOx, ppmvd	--	17	6	2
NOx Measured, ppmvd	<2	15-17	5.6 – 6.4	1.5 (Est.)
Superficial Gas Velocity, fps	7.4	13.3	11.6	10.0
Space Velocity, 1/hr	3,823(6)	6,686(4)	5,624(5)	3,011
Removal Efficiency	95 - 97%(3)	89%	83%	97%

Notes:

1. Staff incorrectly stated catalyst volume as 2,391 ft^3 in Table F.3. 2,975 ft^3 catalyst volume confirmed by NEC with Refinery 5 and via review of SCR data provided by Refinery 5 to SCAQMD.
2. Design value reported as 155 ppmv @ 0% O_2. Value presented in table is corrected to 3% O_2.

3. Measured outlet NOx value of <2 ppmv corresponds to operation of unit with inlet NOx in the range indicated. Removal efficiency based on range of actual operation.
4. Staff reports space velocity value of 2,974/hr in table F.3.
5. Confidential data provided by SCAQMD staff is insufficient to calculate the catalyst volume for this unit without making the following assumption on the depth of a catalyst module which we assume to be 45". Staff used ½ of this value in Table F.3 corresponding to catalyst bed depth (catalyst element height) of 22.5". Recommend staff confirm catalyst volume with Refinery 6.
6. Confidential data on unit design and performance, provided by SCAQMD staff, used to calculate inlet volumetric flow and space velocity. Values differ from staff's entries in Table F.3.

In their review, staff is suggesting that NEC's typical SCR is overdesigned and as a result overpriced. Staff's comparisons suggest an overdesign factor of as much as 284%. We do not agree with this assessment. As can be seen in Table 1, NEC's typical SCR should be able to achieve 97% NOx reduction by virtue of the addition of catalyst at higher gas velocities than the SCR operating at Refinery 1. The typical SCR design provides an approximate 21% margin in space velocity over the Refinery 1 SCR design primarily due to the addition of a third catalyst bed. The addition of a third bed has inherent performance advantages in that it provides for partial redistribution of unreacted NH_3 and NOx versus further cross sectional area additions. If it is determined that the incremental cost of specially fabricated catalyst modules (shorter depth) is low, some further optimization may be possible to reduce SCR cost. It is worth noting that the ~21% catalyst margin will have a 12% overall TIC and PWV cost impact.

Basis of the: ***"mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs"***

The following paragraphs provide background for NEC's use of a 35% conditioning factor for vendor equipment quotes at early stages of projects. These concepts were discussed with SCAQMD staff during reviews of our report and in subsequent follow-up phone conversations and e-mails. Due to the extensive discussion around this topic we are mystified by staff's characterization of this "bid conditioning factor" as, and here I paraphrase, 'an undefined and therefore invalid cost increase'.

Obtaining budgetary quotations from vendors for their equipment is part of the process of developing cost estimates for any project. At the early stages of projects, or when general information is sought, vendors are not provided comprehensive design basis information and therefore do not have a complete picture of the operating envelope for their proposed equipment. In these instances, some vendors will use costs from recent projects and "factor" them to the provided process conditions, other vendors may develop estimates based on equipment designed specifically to meet the provided process conditions. In either eventuality, the vendor is providing a quality estimate with reasonable accuracy (about +/- 10%) for the specified process conditions, without providing a performance guarantee and without review of the specific codes and standards applicable to refinery installations.

As project definition improves the process basis becomes fixed, equipment sizes become more reliable, performance guarantees are finalized, and vendor quote accuracy improves. Industry experience shows that at the early stages of a project, basis uncertainty alone, necessitates the addition of a 15 – 25% conditioning factor to a vendor's budget quote, in addition to other bid conditioning factors, to account for the difference seen between early equipment bids and final, full definition, performance guaranteed, equipment bids based on a definitive project basis.

Refineries are built to a more rigorous set of standards than typical air pollution control equipment which makes projects in the refining sector slightly more expensive than typical industrial projects. Standards which will have an impact on either the SCR design, the structural support design, location of equipment, internal and external maintenance access, etc., are likely to increase Direct SCR M&L costs. At this stage of project definition a factor of 10% is added to a vendor's equipment bid to account for the cost of meeting local plant standards.

The 1.35 "mark-up" or bid conditioning factor used in NEC's cost work-up for all SCR projects (FCCU, Heaters/Boilers, etc.) is not an arbitrary factor used to inflate costs, as implied in Appendix F, but is actually the low end of a time tested and proven means to determine the actual cost of a piece of equipment after full project definition is complete, including application of local industry standards to the design of the equipment, performance guarantees are offered and firm pricing for equipment components is provided by the vendor.

Basis for: ***"Adding another 75% increase in labor to the costs of the manufacturer's SCR."***

Another cost factor discussed with SCAQMD staff, and apparently dismissed as a simple adder to make costs appear high, is the cost of actually installing the equipment supplied by the SCR vendor in the plant. The vendor does not do construction and does not quote the cost of field assembly in their quote which only covers fabrication and supply of the equipment, in this case the SCR catalyst, support frames, ammonia injection grid and the carbon steel box.

The labor cost factor used in NEC's development of project costs is applied to the SCR vendor's factored estimate to account for the labor required to install the manufacturer's equipment at the site, transportation, taxes, tie-ins, insulation, access, structural steel, etc. Installation labor for equipment can range from a low of about 30% of the equipment cost to as much as 200% of direct equipment cost depending on the complexity of the equipment, the material it is made of and other equipment specific factors. In general, low cost equipment manufactured of low cost materials have higher installation percentages than highly complex equipment made of high cost materials. As a reference point, "Applied Cost Engineering", Clark F. D. and Lorenzoni A. B.; Marcel Decker Inc., 1978, uses a factor of 2.2 times direct material costs to estimate the direct M&L cost of a fired heater installation, a factor of 3.0 times direct material costs to estimate the direct M&L cost of a pump installation and a factor of 2.9 to estimate the direct M&L cost of a distillation tower. Due to the simplicity of the SCR equipment and its use of low cost materials we have used an installation labor cost factor of 0.75 (75%) to account for physical installation of the SCR, structural steel, fit-up of ducting, connection of piping, foundations, excavation, instrumentation, insulation, equipment storage, etc. This factor does not account for any costs associated with: demolition of existing equipment, modification of existing equipment, labor inefficiencies attributed to working in an operating plant, relocation and/or modification to underground utilities, piping, piping supports, ammonia storage facilities, control system additions, instrumentation wiring, conduit, power wiring, area paving, area lighting, area utilities, safety facilities, sootblowers, etc.. The cost of these items is rolled up into the overall TIC factor applied to escalate SCR M&L costs to a total project cost.

TIC Factor

SCAQMD staff disputes NEC's use of a TIC factor of 4.5 to convert direct M&L costs for the SCR into TIC for the SCR PROJECT. This factor is a reasonable estimate for project items not specifically identified in the direct M&L costs (indirect costs, engineering and owner's costs, labor productivity, ancillary equipment and systems, revamp items, duct work, area paving, lighting, utilities, safety systems, control system connections and programming, instrumentation, sootblowers, etc.) As a point of reference, the TIC factor used by NEC, in this analysis, is 90% of the average TIC factor of 4.9 used to estimate SOx control costs in NEC's SOx RECLAIM report.

NEC Estimated FCCU Feed Rates from
Flue Gas Rate Data Provided by SCAQMD
Correction of NEC PWVs Required

SCAQMD staff is correct in pointing out that NEC used incorrect design capacities in developing the FCCU SCR costs shown in section 1.2 of NEC's non-confidential report (14-045-4, November 26, 2014). NEC back calculated expected FCCU rates from flue gas flow rate data provided by AQMD staff to obtain estimated FCCU sizes. The following table presents a revision to the report table based on corrected FCCU sizes as indicated by district staff. Also included in the table is an update to the cost of a Grass Roots SCR for Refinery 6 based on a comparison of flue gas rates to the SCR versus the typical (base case) SCR. Revised NEC estimates provided in Table 2 do not include any reduction to NEC's original cost estimate model.

Table 2 (Restatement of Table F.2)
Estimates of PWV Correcting NEC Values for FCCU Feed Rates

Facility	FCCU Feed, kBPD	AQMD's Estimate, $M	Revised NEC Estimate, $M	Ratio: NEC/AQMD
5	71	33	43(2)	1.3
6	90	57	62(1)(2)	1.09
7	55	27	37	1.37
4	34/36(3)	16	28	1.75
9	55	19	37	1.95
Total		152	207	1.36

Notes:

1. The PWV shown includes the impact of additional flue gas from a CO boiler but does not include the incremental flue gas from another source which is fed to the existing SCR.
2. Costs shown are for grass roots (new) SCR additions to existing FCCUs. Existing units may be modified to reduce compliance costs below those indicated.
3. Staff report throughput is 34 kBPD. Published unit capacity is 36 kBPD.

Staff Evaluation of NEC PWVs vs. Refinery 1 SCR Costs Does Not Factor In Project Scope Differences

Staff provided a review of NEC's cost estimates based on a comparison to the cost provided for Refinery 1's SCR to demonstrate that NEC's estimating method is overly conservative. In this comparison staff claims that NEC's cost tool over predicts the cost of this installation by $11M (27%). The difficulty in comparing a specific project to a generalized curve is that the project has a specific scope which in most cases is different than the assumed scope of the "typical" project. This is the case for the SCR installation at Refinery 1 which, according to Refinery 1 personnel, did not include the cost for waste heat boiler modifications. Subtracting this component from the TIC for a typical FCCU SCR installation and recalculating PWV yields a cost of $45.45M which is 10.8% higher than staff's cost work-up on this project of $41M, not the 26% difference indicated in Appendix F. Staff had the WHB cost information NEC used in our estimates, we do not understand why they did not make the PWV comparison on the same basis.

Staff Evaluation of NEC PWVs vs. Refinery 9 SCR Costs Misstates Vendor and NEC Information

Staff also provided a review of NEC's cost estimates based on staff's assessment of differences between the data provided by an SCR vendor to staff and NEC for an installation at Refinery 9. In staff's evaluation of the data provided by the vendor they incorrectly calculate the total catalyst volume to be 3,100 ft^3 vs the actual vendor proposal which provided only 2,400 ft^3. Staff also incorrectly calculates NEC's estimated catalyst volume at 12,697 ft^3 vs an actual value of 4,600 ft^3 (1.92 x vendor proposal, see previous discussion on catalyst volumes and specification of a third bed).

Comments on Staff's Determination of PWVs for FCCU SCRs

I would like to take the opportunity to provide a few comments on SCAQMD staff's determination of PWVs for FCCU SCRs.

1. In using the costs provided for Refinery 1's SCR staff is assuming that all district SCRs can be installed without any impact on upstream equipment and that installation of the SCR can be executed in an open, non congested area. Refinery 1's SCR was installed prior to the installation of a large ESP, which occurred around 2006. If the SCR was to be installed today, or at any time after installation of the large ESP, costs would be higher due to productivity debits associated with working in a congested area and quite possibly even higher due to the need to move or modify some equipment to make the installation possible. In the most extreme case the SCR and ducting may have to be field erected from small fabricated assemblies due to access constraints.

2. Staff used a 0.7 power factor to scale the costs for Refinery 1's SCR project to different sizes. Costs for FCCU regenerator flue gas systems scale more accurately when a figure of around 0.6 is used. The effect of using a larger scale factor is a greater reduction in project costs for all projects with the differences getting proportionately greater the further one gets from the base case unit size. In essence using the 0.7 factor instead of 0.6, in this particular evaluation, will decrease costs for all units and will disproportionately decrease the cost of smaller units.

3. In using vendor budget quotes for SCRs, staff needs to add erection labor to the vendor quote. There is no indication that this is done in staff's analysis.

4. Staff does not condition the vendor's quotes to account for operational conditions, including unit upsets, and other project unknowns which will have direct bearing on SCR design details, performance and costs. An allowance must also be made for the accuracy inherent in vendor's budget quotations, which does not appear anywhere.

5. The PWVs provided for Refinery 7 and Refinery 9 are \$27M and \$19M respectively. There is an apparent inconsistency in these numbers as the stated capacity for each of these units is 55 kBPD. Units of the same capacity should have PWVs close to one another not differing by 42%. Staff should check these numbers and ensure that the SCR project scope differences between these two units can explain the large difference in cost.

In the interest in getting our comments into your hands as soon as possible we will provide comments on Staff's review of our SCR estimates for other applications in the district in one or more separate letters.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc:

NEC – Montville, NJ
P. M. Corritori
J. A. Norton
R. S Todd, PhD
D. Vizzuso
S. Zhang, PhD
Z. Zhang

NEC – Swedesboro, NJ
W. A. Lincoln
C. A. Steves

NEC – New Orleans, LA
S. G. Haydel

AFPM – Washington, DC
A. Adams – AFPM
C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
K. Saffell - Valero
B. Williams - AFPM

Chevron El Segundo Refinery
J. Doyle
S. Worley
R. Spackman

ExxonMobil Torrence Refinery
S. Holm
P. Sheng

Paramount Refining Co.
K. Gleason
H. Chang

P66 LAR
K. Beruldsen
S. Micucci

Tesoro Carson / Wilmington
S. Stark
F. Colcord
D. Kurt

Valero LA Refinery
N. Irwin
M. Smith

WESPA
S. Gornick

Comment Letter #6

California Council for Environmental and Economic Balance
Southern California Air Quality Alliance
Regulatory Flexibility Group
WSPA Western States Petroleum Association

30 January 2015

Dr. Elaine Chang
Deputy Executive Officer, Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: INDUSTRY COMMENTS ON THE NOTICE OF PREPARATION (NOP) OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

Dear Dr. Chang:

These comments are presented on behalf of the members of leading Southern California businesses represented by the California Council for Environmental and Economic Balance ("CCEEB"), the Regulatory Flexibility Group ("RegFlex"), the Southern California Air Quality Alliance ("SCAQA"), and Western States Petroleum Association ("WSPA"). The members of these business groups are major Southern California employers who own and operate facilities in the Regional CLean Air Incentives Market ("RECLAIM") program. 6-1

This "Industry RECLAIM Coalition" formally offers the following comments on the Notice of Preparation and Initial Study for the Draft Program Environmental Assessment ("PEA") for Proposed Amended Regulation XX ("NOP/IS").[1]

1. *The PEA Project Description should specify the potential shave as a range since neither the Proposed Amended Rule nor the Staff's Technical Report is complete.*

The Project Description presented in the NOP and Initial Study ("NOP/IS") incorporates Proposed Amended Rule (PAR) 2002 language as presented in Appendix A of the NOP/IS. At the time of the NOP/IS release, the AQMD had not completed technical work on this rulemaking, with the third-party consultant reviews having not even been released. The cover page for NOP/IS Appendix A did include the following disclaimer: 6-2

"The BARCT evaluation and the RTC shaving methodology are ongoing, so a RECLAIM industry's required RTC shave may change due to the public review process. The

[1] SCAQMD, Notice of Preparation (NOP) of a Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014.

programmatic RTC shave could range from five to 14 tons per day. To provide a worst case scenario of adverse environmental impacts, the adjustment factors and the Non-tradable/Non-usable NOx RTC adjustment factors in Proposed Amended Rule 2002 subparagraph (f)(1)(B) reflect an RTC shave at the higher end of the range to capture a conservative estimate of potential control technologies needed that could generate secondary environmental impacts. As the staff proposal is being refined, if a lesser RTC shave is proposed, the adverse environmental impacts would be less and the Draft PEA and its alternatives will also be further defined."[2]

Now that the third-party contractor reviews have been released, we expect changes are needed to the technical analysis which would alter the technical calculations. Members of this coalition have unresolved questions and concerns about those reviews and the current analysis from AQMD staff. But these reviews and additional inputs from industry stakeholders will necessitate revisions to the draft PAR 2002 language, and more changes will undoubtedly be needed as the rulemaking process progresses. 6-2 Concluded

For this reason, we recommend that the PEA Project Description should explicitly specify the potential shave under this rulemaking as a range. This could be accomplished using language similar to that which was presented on the NOP/IS Appendix A cover page, however this disclosure should be noted in the Project Description section of the main PEA document; not left only in an Appendix.

2. *The PEA should explicitly address at least two project Alternatives: (1) AQMP control measure CMB-01 as approved by the Governing Board (i.e., shave of 3-5 tpd); and (2) the Industry RECLAIM Coalition proposal.*

Under the 2012 Air Quality Management Plan ("AQMP"), the Governing Board approved control measure CMB-01 which authorized further reductions from the NOx RECLAIM program. The control measure authorized by the Governing Board was based on a range of 3-5 tons per day ("TPD") of RECLAIM Trading Credits ("RTCs") being removed from the program. While stakeholders understood the eventual rulemaking could differ, the current Staff proposal as presented in the NOP/IS would be substantially larger at nearly 13 TPD.

This Industry RECLAIM Coalition has presented an alternative methodology for demonstrating command-and-control equivalency. The Industry proposal would reduce the program's quantity of RTCs by limiting the "shave" to only those reductions that can be directly attributed to the advancement of Best Available Retrofit Control Technology ("BARCT"). This Industry proposal could also result in RTC reductions greater than the approved AQMP control measure, but less than those which have been presented by the AQMD Staff. 6-3

We recommend that both of these alternatives should be fully considered as project Alternatives in the PEA, at a minimum.

[2] SCAQMD, NOP/IS for Proposed Amended Regulation XX, Appendix A, 4 December 2014.

Dr. Elaine Chang, SCAQMD
30 January 2015

3. *Public stakeholders should be provided a schedule that is consistent with regulatory requirements while providing reasonable opportunity for stakeholder review and comment.*

The proposed rulemaking could potentially result in significant economic impacts to Southern California businesses and the regional economy. The technical analysis for this rulemaking is not yet complete, and the potential impacts have not yet been fully analyzed or considered. To date, only preliminary technical data has been made available to stakeholders. As such, thorough review and input by the RECLAIM Working Group or other stakeholders has not been possible. 6-4

This Industry RECLAIM Coalition respectfully requests that stakeholders be provided with a rulemaking schedule, including this PEA and the socioeconomic analysis, that is consistent with applicable regulatory requirements but also provides stakeholders a reasonable opportunity for review and comment of the technical bases.

The RECLAIM program remains vitally important to the health of Southern California's economy and environment. The members of this coalition have actively participated in this rulemaking through the NOx RECLAIM Working Group over these last two years, and we look forward to continuing to work with you and the District's Staff on the significant rulemaking. 6-5

Very truly yours,

Bill Quinn
California Council for Environmental and Economic Balance

Michael Carroll
Regulatory Flexibility Group

Curtis Coleman
Southern California Air Quality Alliance

Patty Senecal
Western States Petroleum Association

RESPONSES TO COMMENT LETTER #2
(Alston & Bird LLP on behalf of the
Western States Petroleum Association – October 6, 2015)

2-1 This introductory comment explains the nature of the commenter's organization. No response is necessary.

2-2 SCAQMD staff disagrees with the comment that analysis in the Draft PEA is undermined and lacks adequate analysis because it "narrowly focuses on construction activities associated with construction activities associated with the replacement of NOx emissions control equipment for selected facilities" without having the construction activities confirmed by the District's expert. . In the first place, the Draft PEA analyzes impacts from the construction and operation of control equipment. As explained in Chapter 4, Subchapter 4.0 of the Draft PEA, the installation and operation of new or modified existing NOx emission control equipment at 20 facilities was identified as the only portion of the entire proposal that is expected to result in physical effects that may affect the environment. According to CEQA Guidelines §15126.2, "An EIR shall identify and focus on the significant environmental effects of the proposed project. In assessing the impact of a proposed project on the environment, the lead agency should normally limit its examination to changes in the existing physical conditions in the affected area as they exist at the time the notice of preparation is published..." For this reason, the analysis in the PEA focuses on the physical effects that may occur as a result of constructing new or modifying existing NOx control equipment and operating the equipment once constructed.

Further, the majority of the data and information relied upon to analyze the environmental impacts for the proposed project was provided by the consultants hired by the SCAQMD. So, it is incorrect to imply that the SCAQMD's consultants would not support the analysis. Additional data and methodologies from previous CEQA documents such as the Final EA for NOx RECLAIM[1] that was certified in January 2005 and the Final PEA for SOx RECLAIM[2] that was certified in November 2010, were also relied upon to prepare this PEA. The same consultants provided data for both this PEA and the Final PEA for SOx RECLAIM. Finally, several other references were used to prepare the extensive PEA. For a complete list of the references relied upon for the preparation of this PEA, see Chapter 6 – References.

The comment also states that the Draft PEA did not examine a reasonable range of alternatives because the majority of alternatives called for a "shave" of 14 tpd or more. However, the Draft PEA specifically considered the Industry Approach (Alternative 3)

[1] SCAQMD, Final Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2004, SCAQMD No. 031104BAR, certified January 7, 2005. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2005

[2] SCAQMD, Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), October 2010, SCAQMD No. 06182009BAR, SCH No. 2009061088, certified November 5, 2010. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2010/final-program-environmental-assessment-for-proposed-amended-regulation-xx.pdf?sfvrsn=4

and identified that this alternative would result in fewer impacts during construction and operation than the proposed project. Any alternative with a shave smaller than 14 tpd but larger than the Industry Approach would have environmental impacts in between those identified for the proposed project and the Industry Approach, as it would be expected to result in a lessened need and use of new control equipment. Most of the alternatives included a 14 tpd shave because that is the size of the shave staff believes is necessary to reach BARCT-level emissions from the RECLAIM universe. CEQA does not require consideration of alternatives that do not meet most of the basic project objectives. See CEQA Guidelines §15126.6. Neither this comment letter nor any earlier comment letter identifies another alternative that should have been analyzed that will meet the basic project objective of achieving BARCT levels of emissions. Specific comments raised individual resource areas that are addressed below.

2-3 The comments raised in Attachment 1 have been individually bracketed and numbered as Comments 2-49 through 2-88. See Responses 2-49 through 2-88.

2-4 The three additional letters referenced in this comment were included with Comment Letter #2 and Attachment 1 to Comment Letter #2. The August 21, 2015 letter was primarily written relative to the Preliminary Draft Staff Report for the proposed project and did not raise new or different CEQA issues than what was already raised in the January 30, 2015 letter that was submitted relative to the NOP/IS. The January 30, 2015 letter along with responses were included in the Draft PEA (see Appendix G, Comment Letter #6 and Responses to Comment Letter #6). Because the August 21, 2015 letter was transmitted to the SCAQMD after the Draft PEA was released for public review and comment, separate responses to the August 21, 2015 letter could not have been included or addressed in the Draft PEA. However, responses to the August 21, 2015 letter have been prepared and are included in the Revised Draft Staff Report for NOx RECLAIM as Comment Letter #1 (see Appendix Z, pp. 241-340)[3]. (To avoid confusion, it is important to note that the letter dated August 21, 2015 also contains a document labeled as Attachment 1 which is a different document from Attachment 1 to Comment Letter #2 in this PEA.)

The May 27, 2015 letter was written relative to the NOx RECLAIM Working Group held on April 29, 2015 and contains comments relative to the staff proposal and CEQA. However, the majority of the comments in the May 27, 2015 letter focus on non-CEQA issues that have been superseded by subsequent, more recent letters and corresponding responses that reflect the updated staff proposal (see Appendix Z of the Revised Draft Draft Staff Report). To avoid confusion and repetition of what are now moot comments, only the CEQA-related comments contained in the May 27, 2015 letter have been bracketed (see Comments 2-89, 2-90, and 2-91) and responses have been prepared (see Responses 2-89, 2-90, and 2-91).

[3] SCAQMD, Revised Draft Staff Report, Proposed Amendments to Regulation XX, Regional Clean Air Incentives Market (RECLAIM), NOx RECLAIM, November 4, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaim_dsr_110415.pdf?sfvrsn=4

2-5 This comment neither elaborates on the commenter's concerns with the proposed rule amendments and the Draft PEA nor explains why the commenter believes the requirements under CEQA have not been satisfied. This comment also broadly alleges that the Draft PEA contains errors, does not disclose all significant impacts, and does not allow the consideration of feasible mitigation measures or project alternatives to reduce or avoid impacts without providing any justification or evidence to support revising the proposed rule amendments and the Draft PEA and recirculating the Draft PEA. To the extent that the commenter provides more specificity on the concerns elsewhere in this letter, responses to the more specific concerns have been provided. SCAQMD staff does not agree that the CEQA document needs to be recirculated.

2-6 This comment describes the purpose of an EIR and reiterates earlier statements that the Draft PEA is flawed and includes errors, without providing specific information to support that assertion. As explained in Response 2-4, the August 21, 2015 letter was transmitted to the SCAQMD in response to Preliminary Draft Staff Report for the proposed project and not to the Draft PEA. Further, the August 21, 2015 letter did not raise new or different CEQA issues than what was already raised in the January 30, 2015 letter that was submitted relative to the NOP/IS. Because adequate responses were prepared for the January 30, 2015 letter and included in the Draft PEA, SCAQMD staff does not believe that a revision to the Draft PEA and a recirculation of the document for another public review and comment period is necessary.

2-7 This comment provides multiple quotes from CEQA case law relative to the general content requirements of a project description. SCAQMD staff is well aware of the CEQA requirements for a project description as described in CEQA Guidelines §15124 and the contents of the Draft PEA comply with these requirements.

2-8 As stated in the quote from the Draft PEA found in this comment, the project consists of the proposed amendments to Regulation XX, which includes, among other things, a proposal to reduce NOx RTC holdings by 14 tpd. The project description outlines the entire project and details all of the changes that are proposed to Regulation XX (see Chapter 2, Section 2.3 of the PEA, pp. 2-3 through 2-5). The comment alleges that the Draft PEA fails to evaluate the potential environmental effects of "effectively eliminating the RECLAIM market." However, SCAQMD staff does not believe the amendments would "effectively eliminate" the RECLAIM market as there would still be over 20 percent of unused RTCs even after the shave under SCAQMD's staff proposal and WSPA has admitted that the market has functioned with 15 percent of unused RTCs in the past. Moreover, the comment does not supply substantial evidence that any adverse environmental impacts would result from the elimination of the RECLAIM market, should that occur. State law would still require the identified BARCT to be implemented (Health and Safety Code §§40440 and 40919), which would still require similar construction and operation of control equipment as what was analyzed in the Draft PEA.

The comment also states that it is misleading to characterize the proposed project as merely a series of construction projects to achieve BARCT requirements. As explained above, the project description fully describes the proposed project. Further, as explained in Chapter 4, Subchapter 4.0 of the Draft PEA, the installation and operation of new or modified existing NOx emission control equipment at 20 facilities was identified as the only portion of the entire proposal that is expected to result in physical effects that may affect the environment. According to CEQA Guidelines §15126.2, "An EIR shall identify and focus on the significant environmental effects of the proposed project. In assessing the impact of a proposed project on the environment, the lead agency should normally limit its examination to changes in the existing physical conditions in the affected area as they exist at the time the notice of preparation is published..." For this reason, the analysis in the PEA focuses on the physical effects that may occur as a result of constructing new or modifying existing NOx control equipment and operating the equipment once constructed. Thus, the differences between the general introduction of the proposed project to the reader, what is contained in the project description, and the physical effects of the proposed project and its corresponding analysis in the PEA are not inconsistent with each other and do not represent a shift among different project descriptions that would undermine the CEQA process as a vehicle for public participation.

The comment also states that the amendments can have 'wide ranging impacts" that are not limited to BARCT implementation but also on the operation of the facilities. However, the comment fails to identify any such potential impact. If, for example, a facility were to reduce operations rather than install control technology, adverse environmental impacts beyond those that would result from the construction and operation of controls are not foreseeable. CEQA does not call for an analysis of economic impacts unless they result in adverse environmental impacts, and none have been identified. See CEQA Guidelines §15064 (e).

In addition, the public, stakeholders and interested parties alike were afforded extra time than is required by CEQA for the review and comment periods. For example, the NOP/IS was released for a 57-day public review and comment period when this type of CEQA document is only required to be released to responsible and trustee agencies for their 30-day review and comment period. The Draft PEA was released for a 53-day public review and comment period when this type of CEQA document normally requires a 45-day public review and comment period.

2-9 As explained in Response 2-8, analysis of the potentially significant impacts of the proposed project in the PEA focused on both construction and operation activities, and not just construction activities, as the comment claims. SCAQMD staff's determination that BARCT construction activities as well as operation activities can actually be performed was based on the consultants' reports and previous CEQA documentation for similar projects as described in Response 2-2. RECLAIM does not prescribe that each of these control equipment be installed, as there is flexibility for facility operators to make other changes to reduce emissions or purchase RTCs to meet their requirements. The Draft PEA analyzes the impacts of installation and operation of all of the control equipment, which puts an upper bound on potential environmental impacts. The purpose of the project (e.g., the project objectives) is outlined in Chapter 2, Section 2.2 of the

PEA. Contrary to the comment, all of the project objectives were considered in the analysis of the various components of the proposed project and the alternatives.

2-10 As explained in the responses to Comment Letter #1 in the Revised Draft Staff Report (Appendix Z) released November 4, 2015, after review of the consultants' report, SCAQMD staff and Norton Engineering (NEC) agreed on the proper BARCT levels for all but one of the source categories analyzed (boilers/heaters). Therefore, NEC and SCAQMD staff agreed on which emission reductions were technically feasible and cost-effective for each refinery source category. To address the remaining difference of opinion regarding the refinery boilers/heaters, SCAQMD staff reduced the amount of the proposed shave by 0.79 tpd, substantially more than the equivalent NOx reductions that would be eliminated using the Norton Engineering approach (0.33 tpd). Thus, while disagreeing with NEC's BARCT analysis, the SCAQMD has effectively used the NEC BARCT determination. Regarding WSPA's claim that the BARCT requirements may not be cost-effective, as noted above, Norton Engineering and SCAQMD staff agreed on almost all BARCT levels, including that they were cost-effective, and SCAQMD staff adjusted for the one category of remaining disagreement. While WSPA states that its consultant reached a different cost number, that consultant has declined to provide SCAQMD staff with any of the information that went into its total cost number, so SCAQMD staff has no way of verifying the consultant's work. Since the WSPA cost number is unsubstantiated, it is not substantial evidence. Furthermore, if WSPA were correct, and some of the assumed BARCT measures are not cost-effective, this still would not have foreseeable increased adverse environmental effects beyond those resulting from assuming that all identified BARCT measures would in fact be implemented.

As explained in Response 2-4, the issues raised in the August 27, 2015 letter, including those relative to the technical feasibility of the proposed BARCT requirements which are contained throughout the letter, have been responded to by SCAQMD staff. See Revised Draft Staff Report, Appendix Z, pp. 241-340.

2-11 The claim that the proposed 2 ppm NOx levels using new or modified SCR is unsubstantiated, is a repeat of comments expressed in the August 27, 2015 letter. See Revised Draft Staff Report, Appendix Z, Comments 1-7 and 1-8, p. 246; and Responses to Comments 1-7 and 1-8, pp. 274-277. See also Response 2-10 above. The Norton Engineering letter attached to WSPA's comment letter states "we agree that 2 ppmv (3%02) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines, and TGUs/SRUs, with caveats." The caveats had to do with design features and the costs it would take to achieve these levels. As explained in Response 2-10, SCAQMD staff adjusted the shave to account for the one area (boilers/heaters) where the cost differences between Norton Engineering's approach and SCAQMD staff's approach would potentially make a difference in cost-effective BARCT levels. Again, this comment does not explain how this issue would result in significantly increased adverse environmental impacts beyond those already analyzed.

2-12 The comment pertaining to implementation schedule is a repeat of the sentiments expressed in the August 27, 2015 letter, Comment 1-21. See Revised Draft Staff Report, Appendix Z, Comments 1-21, pp. 252-253; and Response 1-21, p. 284.

In addition, the PEA recognizes and acknowledges the scheduling difficulties that may occur with regard to implementing construction projects at refineries. Without definitively knowing what each refinery operator will ultimately do and their corresponding schedule, the PEA contains assumptions that represent a worst-case analysis as explained in the air quality and GHG analysis in Chapter 4, Subchapter 4.2, page 4.2-10:

> *"Typically construction projects have staggered construction schedules which take into account design and engineering, ordering, purchasing and delivery of equipment, permitting and environmental review, the availability of construction crews, budgeting, and any other construction projects on site. However, due to wide range of construction time necessary to build the various types of NOx control equipment, the construction activities at other affected facilities could overlap. However, because of widely varying turnaround schedules of affected equipment within any given facility and based on past construction projects involving major construction equipment where the SCAQMD was the lead agency, the analysis in this PEA includes a conservative assumption that all of the refineries will have overlapping construction activities occurring in one year. However, since having all facilities construct all NOx controls within the first year is unlikely, for demonstrative purposes, the analysis also includes an analysis of the overlapping impacts spread out over a five- and seven-year period."*

Thus, if the actual construction activities at the affected refineries are not implemented at all or end up being spread out over eight years, then the environmental impacts on a peak daily basis would be less than what is analyzed in the Draft PEA, but would still likely have significant adverse impacts.

2-13 As explained in Response 2-2, the analysis in the Draft PEA relies on data and methodologies from previous CEQA documents such as the Final EA for NOx RECLAIM that was certified in January 2005 and the Final PEA for SOx RECLAIM that was certified in November 2010, for example. Both of these documents address the potential aesthetics impacts in a similar manner. In addition, both of the NOP/ISs prepared for these projects address the potential noise impacts in a similar manner and conclude that the noise impacts would be less than significant at the NOP/IS stage. In addition, as cited in Chapter 6 of the PEA, the following CEQA documents for other projects that have been certified and for which the SCAQMD was the lead agency also provided excellent source materials for the preparation of this PEA, especially with regards to evaluating the various potential impacts at refinery facilities. Moreover, no noise issues were raised relative to these referenced CEQA documents.

1. SCAQMD, 2001. Final Environmental Impact Report for: ARCO CARB Phase 3/MTBE Phase-Out Project, SCH. No. 2000061074; certified May 2001.

2. SCAQMD, 2001. Final Environmental Impact Report for: Chevron El Segundo CARB Phase 3 Clean Fuels Project, SCH. No. 2000081088; certified November 2001.

3. SCAQMD, 2001. Final Environmental Impact Report for: Proposed Equilon Enterprises LLC CARB Phase 3 Reformulated Gasoline Project, SCH. No. 2000091086; certified October 2001.

4. SCAQMD, 2001. Final Environmental Impact Report for: Mobil CARB Phase 3 Reformulated Gasoline Project, SCH. No. 2000081105; certified October 2001.

5. SCAQMD, 2001. Final Environmental Impact Report for: Proposed Tosco Los Angeles Refinery Phase 3 Reformulated Fuels Project, SCH. No. 2000091056; certified April 2001.

6. SCAQMD, 2001. Final Environmental Impact Report for: Proposed Ultramar Wilmington Refinery – CARB Phase 3 Project, SCH. No. 2000061113; certified December 2001.

7. SCAQMD, 2007. Final Environmental Impact Report for the ConocoPhillips Los Angeles Refinery PM10 and NOx Reduction Projects, SCH No. 2006111138, certified June 2007.

Assuming the comment means that the PEA should have evaluated noise impacts at individual facilities, the commenter did not bring up this issue in their letter submitted relative to the NOP/IS which was released for 57-day public review and comment period from December 5, 2014 to January 30, 2015 (see Appendix G, Comment Letter #6). The NOP/IS concluded that the noise impacts would be less than significant and since the commenter's concern relative to noise was not raised during the NOP/IS comment period, the PEA did not further analyze noise impacts beyond what was contained in the NOP/IS.

The noise analysis in the NOP/IS was based on best available information for a program level analysis, because the SCAQMD is not required to conduct a project level analysis. [CEQA Guidelines § 15187 (e)]. Further, the noise environment at the refineries is dominated by refinery equipment, other heavy industrial activities, and traffic. Construction activities for the proposed project are expected to generate noise associated with the use of heavy construction equipment and construction-related traffic. Noise levels during construction are measured from the center of the construction activity and most of the construction noise sources will be located at or near ground level, so the noise levels are expected to attenuate over distance. If and when each actual construction project is proposed as a result of complying with the proposed project, each individual facility operator will have to comply with the local noise element and ordinances applicable to their facility location during both construction and operation after build-out.

Regarding the topic of aesthetics, this PEA (as well as the Final PEA for SOx RECLAIM in 2010) relied upon the extensive aesthetics analysis conducted for the wet gas scrubber

(WGS) installation as analyzed in the referenced document number 7 above as suitable example of a typical WGS project. The commenter provides no evidence that a different aesthetics conclusion would be reached if a WGS was installed at any of the other refineries. Of course, should an individual refinery operator choose to install a WGS, the project will require a CEQA review to compare their individual project issues with the conclusions reached in this PEA. Should facility-specific circumstances cause a conclusion for the topic of aesthetics, noise, or any other environmental topic for that matter, to be different than what was analyzed in the NOP/IS and PEA, an additional CEQA document may be necessary for that future project.

Finally, it is important to keep in mind that a program CEQA document, by design, provides the basis for future environmental analyses and will allow future project-specific CEQA documents, if necessary, to focus solely on the new effects or detailed environmental issues not previously considered. If an agency finds that no new effects could occur, or no new mitigation measures would be required, the agency can approve the activity as being within the scope of the project covered by the program CEQA document and no new environmental document would be required [CEQA Guidelines §15168 (c)(2)].

2-14 This comment states that the PEA should identify realistic assumptions based on facts but it does not identify what the assumptions should be. The comment also states that the PEA has dismissed the potential for environmental impacts based on the facilities' industrial locations. This comment is inaccurate. The PEA thoroughly analyzes potential impacts in all CEQA topic areas identified in the NOP/IS, and does not "dismiss" such impacts based on the project being in an industrial area. If this comment refers to the analysis of the aesthetic impacts of a plume from a wet-gas scrubber, see Response 2-13 above. If the suggestion that "realistic assumptions" be applied instead of reasonable assumptions means that the PEA should attempt to speculate about what facility operators would actually do (and when) to comply with the proposed project, this is not what CEQA requires. See CEQA Guidelines§§15145 and 15384. Instead, in order to provide a conservative approach, the analysis assumed overlapping construction and operational activities. Adjusting to "realistic assumptions" would likely result in less concentrated, overlapping construction and operation activities, would not represent a conservative, worst-case analysis, and would undermine the PEA's ability to disclose all significant impacts.

In evaluating the proposed project at the beginning of the rule development, SCAQMD staff determined that there is substantial evidence that the project may have a significant effect on the environment, and decided to prepare a PEA as an equivalent CEQA document to an environmental impact report in accordance with the SCAQMD's certified regulatory program. CEQA Guidelines §15384 defines substantial evidence as fact, a reasonable assumption predicated upon fact, or expert opinion supported by fact and further explains that substantial evidence is not argument, speculation, unsubstantiated opinion or narrative, evidence that is clearly inaccurate or erroneous, or evidence of social or economic impacts that do not contribute to, or are not caused by, physical impacts on the environment. The commenter's claims of potential additional impacts are mere speculation and unsubstantiated argument. Thus, the PEA is based on reasonable assumptions supported by facts provided by the consultants and the reference materials listed in Chapter 6 of the PEA.

2-15 SCAQMD staff disagrees that any alteration or recirculation of the PEA is necessary. This comment repeats previous comments and adds the claim that the document should be recirculated. However, this comment does not identify any new significant impacts that would require recirculation nor does it establish that the PEA is "fundamentally and basically inadequate or conclusory." See Responses 2-12 through 2-14.

2-16 The evaluation in the PEA of the various possible physical actions that may be taken by facility operators to comply with the proposed project as well as their associated environmental impacts is based partially on facility-specific information provided either to SCAQMD staff or the consultants. While the analysis is quite extensive, it does not reflect a project-level review because none of the information provided confirms what each facility operator will ultimately do between now and 2022. The PEA is consistent with the criteria in CEQA Guidelines §15187 which requires air quality management districts, when adopting a rule or regulation that requires the installation of pollution control equipment or establishing a performance standard, to perform an environmental analysis of the reasonably foreseeable methods by which compliance with the rule or regulation will be achieved. In particular, the environmental analysis in the PEA includes reasonably foreseeable: 1) environmental impacts of the methods of compliance; 2) mitigation measures relating to those impacts; and, 3) alternative means of compliance which would avoid or eliminate the identified impacts. [CEQA Guidelines § 15187 (c)]. Further, while the SCAQMD may utilize numerical ranges and averages where specific data is not available for preparation of the PEA, the SCAQMD is not required to, nor should it, engage in speculation or conjecture. [CEQA Guidelines § 15187 (d)]. Finally, the SCAQMD is not required to conduct a project level analysis. [CEQA Guidelines § 15187 (e)]. For these reasons, the PEA analysis is in fact a program analysis as it contemplates a combination of potential future activities, without knowing all of the actual details of individual projects that would be undertaken in the future by facility operators.

The same type of analysis was conducted in the Final PEA for SOx RECLAIM, which affected a smaller number of facilities with some overlapping of the NOx RECLAIM universe of sources. While the Draft PEA describes construction impacts that are likely to result from implementing the rule amendments, SCAQMD staff recognizes that additional CEQA review may be necessary as the facilities implement their specific projects to meet the emission reduction requirements. The SCAQMD staff has not sought to transform a rule-making into a construction project but rather has analyzed the expected environmental impacts of implementing the proposed amended regulation, which are the impacts of constructing and operating emission reduction projects. See also Responses 2-2 and 2-8.

Regarding the comment that the topic of noise was not evaluated in the PEA, see Response 2-13.

2-17 This comment requests a clarification as to how CEQA Guidelines §15253 – Use of an EIR Substitute by a Responsible Agency, has been satisfied. In the first place, CEQA Guidelines §15253 does not impose any requirements on an agency having a certified program, such as the SCAQMD. CEQA Guidelines §15253 (c) provides that "certified agencies are not required to adjust their activities to meet the criteria in subdivision (b)." Instead, if those criteria are not met, responsible agencies must "comply with CEQA in the normal manner." CEQA Guidelines §15253 (c)(2). Nevertheless, SCAQMD staff has appropriately consulted with responsible agencies. In accordance with CEQA Guidelines §15082, a NOP, which included a notice of a scoping meeting, was provided to all responsible agencies at the same time the NOP/IS was released for a 57-day public review and comment period. The SCAQMD did not receive any responses to the NOP from any responsible agency. Responsible agencies were also notified of the availability of the Draft PEA at the same time the document was released for a 53-day public review and comment period. Again, the SCAQMD did not receive any comments on the Draft PEA from any responsible agency. Thus, SCAQMD staff is unaware of any responsible agencies that may have concerns about the proposed project.

The Final PEA along with all of the other project documents (e.g., proposed rule language, Staff Report, Socioeconomic Report, et cetera) is scheduled to be presented to the SCAQMD Governing Board for consideration and approval. If the project gets approved and the Final PEA gets certified, only then can a responsible agency use the Final PEA in place of an EIR or Negative Declaration for a future project provided that all of the conditions in CEQA Guidelines §15253 (b) are met.

2-18 This comment contains similar sentiments expressed in more detail in Comments 2-2, 2-8, 2-9, and 2-10. See Responses 2-2, 2-8, 2-9, and 2-10. The comment does not provide any evidence of improper evaluation of construction impacts or infeasibility of the proposed BARCT (best available retrofit control technology).

2-19 SCAQMD staff disagrees that the PEA overlooks the impacts from the whole of the project. See Responses 2-2, 2-8, 2-9, and 2-10.

CEQA Guidelines §15064 (e) provides that the economic or social effects of a project shall <u>not</u> be treated as significant effects on the environment. CEQA Guidelines §15064 (e) further states:

"Economic or social changes may be used, however, to determine that a physical change shall be regarded as a significant effect on the environment. Where a physical change is caused by economic or social effects of a project, the physical change may be regarded as a significant effect in the same manner as any other physical change resulting from the project. Alternatively, economic and social effects of a physical change may be used to determine that the physical change is a significant effect on the environment. If the physical change causes adverse economic or social effects on people, those adverse effects may be used as a factor in determining whether the physical change is significant. For example, if a project would cause overcrowding of a public facility and the overcrowding causes an

adverse effect on people, the overcrowding would be regarded as a significant effect."

Thus, instead of economic or social changes, the focus of the analysis in PEA shall be on the physical changes. [CEQA Guidelines §15131 (a)] For this reason, the analysis in the PEA does not address the costs associated with achieving the proposed NOx emission reductions. Instead, a socioeconomic analysis has been conducted and the analysis and findings are presented in a separate document, Socioeconomic Report For Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM) that was initially published on September 9, 2015 and subsequently revised on October 6, 2015 and November 4, 2015[4]. The socioeconomic analysis addresses the issues and socioeconomic impacts relating to the availability of RTCs to provide structural buyers a source of credits and to provide for NSR holding required by New Source Review. The socioeconomic analysis also addresses the potential cost impacts that may result from the construction and operation of new or modified NOx emissions control equipment that may be installed as a result of the proposed project.

2-20 As explained in Chapter 4, Subchapter 4.0 of the Draft PEA, the installation and operation of new or modified existing NOx emission control equipment at 20 facilities was identified as the only portion of the entire proposal that is expected to result in physical effects that may affect the environment. This comment claims it is a "clear fact" that the proposed amendments could "potentially eliminate the NOx RTC market" but no evidence or data is given to support this assertion. WSPA has conceded in past submittals that the market has functioned with as little as 15 percent excess unused RTCs. (See Special Stationary Source Committee Presentation, September 23, 2015). Even after the shave is fully implemented in 2023, there are expected to be over 20 percent excess unused RTCs. Thus, SCAQMD staff expects that there will be sufficient RTCs for the market to continue to function. Moreover, the comment fails to identify any physical impacts that might result from a failure of the market to function effectively. See also Response 2-19.

2-21 At the time the NOP/IS was published, SCAQMD staff identified 275 facilities that are currently in the NOx RECLAIM universe of sources and these 275 facilities are considered to be part of the existing environmental setting or baseline. For this reason, the reduction in the number of facilities that participate in the NOx RECLAIM program over the years from 392 to 275 is not a product of the proposed project that would require an analysis in this PEA. Moreover, there is no evidence that RECLAIM was in any way the cause of a significant number of facilities shutting down. Each year, the SCAQMD

[4] SCAQMD, Draft Final Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), November 4, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaim_dfsocio_110415.pdf?sfvrsn=2.
SCAQMD, Revised Draft Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), October 6, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/reclaim_revisedsociodraft.pdf?sfvrsn=2.
SCAQMD, Draft Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), September 9, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/reclaim_sociodraft_090915.pdf?sfvrsn=4.

staff prepares a program audit and report to the SCAQMD Governing Board pursuant to Rule 2015 (b) which includes the facilities that have shut down and the reasons given for their shutdown. SCAQMD staff has reviewed all annual program audits and concluded that although about 178 facilities have shut down (while about 50 new facilities have entered the market), only three facilities identified RECLAIM as a reason for their shutdown and only 10 identified environmental regulations other than RECLAIM as a reason for their shutdown. Since SCAQMD staff did not follow up on these shutdowns, it is unclear even for those who identified RECLAIM, that it was the sole reason for shutting down. In any event, since the majority of facilities that shutdown did not identify RECLAIM as the cause, any resulting environmental impacts from the shutdowns are also not caused by RECLAIM. Based on this past history, and the fact that the market will continue to have a comparable level of excess unused RTCs even after the shave is fully implemented as it has had historically, no significant number of facility shutdowns and thus no resulting significant environmental impacts can be predicted.

2-22 As explained in Response 2-21, the reduction in the number of participants in the NOx RECLAIM program is not a consequence of the proposed project. Thus, any loss in productivity due to the reduced number of participants is also not a consequence of the proposed project. Further, it would be speculative to assume that there will continue to be a decline in the number of NOx RECLAIM participants as a result of the proposed project. As also explained in Response 2-21, the majority of past facility shutdowns have not been caused by RECLAIM, and there will be sufficient RTCs for the market to continue to function, so it is not expected that RECLAIM will cause facility shutdowns in the future.

The energy analysis in the PEA evaluated a potential increase in energy demand during both construction and operation activities that may occur as a result of the proposed project. If the number of NOx RECLAIM participants reduces below 275, then that could mean that less energy would be needed for operation of these facilities, so any concerns with energy reliability would be moot. Without knowing what the lowered participation would be, it would be speculative to estimate what the corresponding reduction in energy needs would be. With respect to adequate power supply, the rule includes provisions to address the needs of electricity generating facilities, including a Regional NSR Holding Account that will be taken from the shaved RTCs and not submitted into the SIP, so that facilities can use these RTCs to satisfy their NSR holding requirements. Also, electricity generating facilities will have access to RTCs to offset their emissions in the event of a State of Emergency declared by the Governor. In addition, the proposal now includes an option for EGFs to exit RECLAIM if certain requirements are met. Such facilities will only use this option if it is to their benefit.

This comment further suggests that the PEA should consider the environmental impacts of "leakage" which is a known impact of subregional cap and trade programs. According to the Initial Statement of Reasons for the California Air Resources Board Cap-and-Trade Program for greenhouse gases, requirements to reduce emissions can create a disadvantage for facilities subject to the cap compared to other facilities, which could cause production and the resulting emissions to shift to facilities outside the cap. This is called "leakage" and is most likely to happen in an industry where there are higher levels of emissions per unit of output, and where it is difficult for a particular industry to pass through costs[5]. The theory of leakage, however, assumes that comparable sources outside the cap will not be subject to any restrictions; hence, the competitive disadvantage for capped sources. In this case, BARCT is still a requirement for all air districts that are classified as "moderate" for the state ozone standard or above. [Health and Safety Code §40919.] Thus, there is not likely to be a large competitive disadvantage for RECLAIM sources, at least compared to comparable sources within the state. Finally, the California Air Resources Board chose to ameliorate "leakage" impacts by providing free allocations to industries that are at risk of leakage[6]. In RECLAIM, all facilities except those that were newly-constructed after the inception of the program received free allocations, so the program already includes measures to ameliorate leakage. Based on the foregoing, it would be speculative to predict increased NOx emissions resulting elsewhere from the impact of leakage that need to be analyzed under CEQA.

2-23 The SCAQMD's reasoning about how the environmental impacts were identified and analyzed have been previously addressed in Responses 2-2, 2-8, 2-9, and 2-10.

SCAQMD staff believes that the PEA contains an adequate analysis based on the best facts and evidence available. This comment asserts that the rule amendments will cause facilities to react in ways that are reasonably foreseeable (other than installing BARCT-level controls) and will have environmental impacts, but fails to identify what such reactions would be. The comment is too general to enable further response.

2-24 This response contends that the proposed rule amendments "manipulate" the market and will have foreseeable consequences because they are imposed in a "targeted, uneven manner" rather than "across the board." SCAQMD staff disagrees that the proposed amendments are "uneven." To derive the proposed shave, SCAQMD staff examined what source categories could feasibly further reduce emissions by implementing new BARCT, identifying a total of 11 categories, of which about half were source categories located at refineries. SCAQMD staff then identified the level of reductions that would be achievable for the refinery and non-refinery categories, resulting in proposed reductions of about 66 percent for refinery categories and 49 percent for non-refinery categories. SCAQMD staff then proposed a shave methodology that spread the BARCT reductions among 56 facilities that together account for 90 percent of the NOx RTC holdings in RECLAIM. The percent shave was proportional to the available reductions, i.e., 66 percent for refineries and 49 percent for non-refineries. Approximately 219 facilities holding the remaining 10 percent, for which no BARCT was identified, are not proposed

5 State of California, Air Resources Board, Proposed Regulation to Implement the California Cap-and-Trade Program, Part 1, Volume 1, Staff Report: Initial Statement of Reasons, October 28, 2010, p. II-26. http://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf

6 State of California, Air Resources Board, Proposed Regulation to Implement the California Cap-and-Trade Program, Part 1, Volume 1, Staff Report: Initial Statement of Reasons, October 28, 2010, p. II-26. http://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf

to be shaved. Thus, the shave is more equitable than an across-the-board shave, which would require substantial reductions (an average of 53 percent) from facilities that do not have such reductions available, while shaving refineries by a percentage that is much less than their available reductions. As a result, SCAQMD staff believes the proposed amendments will have a far less adverse effect on the market than an across-the-board shave would have. This comment alleges that the PEA has not analyzed the "whole of the project" but for the reasons stated, SCAQMD staff believes the proposed amendments would have less impact than an across-the-board shave. For an explanation of how SCAQMD staff determined the environmental impacts of the project, see also Response 2-19.

2-25 This comment asserts that the PEA does not analyze "the whole of the action" and implies that the analysis constitutes "piecemealing." The comment fails to identify what future or other activities will allegedly result from adopting the rule that have not been analyzed. In addition, the preparation of a PEA that contains a program level analysis in anticipation of future activities is not piecemealing because "a showing of improper piecemealing requires evidence of a reasonably definite and concrete plan for future activities.[7]" The PEA acknowledges that implementation of the proposed project may result in the construction and operation activities that may cause environmental impacts for some facilities. However, it is also possible that these same facilities may choose to purchase more NOx RTCs to comply with the proposed project instead of installing new or modifying existing air pollution control equipment. Certainty as to which path will be followed at each affected facility may be provided when, for example, facility operators submit permit applications to construct new or modify existing air pollution control equipment. To date, SCAQMD staff is unaware of any permit applications that have been submitted in anticipation and in advance of the proposed project being considered for adoption by the SCAQMD Governing Board. Facility operators tend to wait to follow up with a permit application until after the SCAQMD Governing Board makes a final decision to approve a rule amendment. Thus, for the purpose of preparing the PEA, uncertainty exists and the analysis in the PEA reflects the understanding that there is currently no reasonably definite and concrete plan for future activities that will occur at the affected facilities.

2-26 This comment asserts that the socioeconomic analysis does not delve into the potential physical effects resulting from the NOx RTC shave. SCAQMD has been unable to identify such effects, nor does the comment identify them.

The comment also asserts that the PEA should be recirculated after WSPA provides its comments on the Socioeconomic Report. SCAQMD staff is only required to recirculate the PEA if any of the conditions identified in CEQA Guidelines §15088.5 occur. See also Response 2-19.

2-27 This comment asserts that the Draft Socioeconomic Report was circulated on September 7, 2015 - weeks after the Draft PEA, and the socioeconomic analysis should have been

[7] Berkeley Keep Jets Over the Bay Committee v. Board of Port Commissioners (2001) 91 Cal. App. 4th 1344, 1360-1362.

prepared before, or at least in conjunction with, the Draft PEA. There is no requirement in CEQA for any socioeconomic analysis to occur, let alone any requirements for the timing of such an analysis. In this case, the Draft Socioeconomic Report was released one month before the close of comments on the Draft PEA on October 6, 2015. Thus, there was ample time and opportunity to take the socioeconomic analysis into consideration when preparing CEQA comments. In addition, in response to comments received, a Revised Draft Socioeconomic Report was released on October 6, 2015 and a Draft Final Socioeconomic Report was released on November 4, 2015. See also Response 2-19.

This comment also claims that the SCAQMD staff proposal used $50,000 per ton as a cost-effectiveness threshold and that such a threshold could result in operational changes which have physical impacts on the environment, which should be analyzed in the Draft PEA. As set forth in the Draft Final Socioeconomic Report as revised on November 4, 2015 (see page 13, Table 7), the average cost-effectiveness for the BARCT measures is $13,615 per ton, not $50,000 per ton. The cost-effectiveness for the refinery measures ranges from $2,000 to $34,000 per ton. Even at the upper end, this is comparable to the upper end of cost-effectiveness for other command-and-control measures for combustion sources, such as SCAQMD Rule 1146.1 - Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters and Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (up to lower $30,000s). In any event, the Draft PEA assumes that all identified BARCT will be installed, and thus, projects the potential reasonable worst case environmental impacts. If a facility finds a more cost-effective measure to implement instead, or decides to reduce production, this would likely result in fewer, not more, environmental impacts than assumed in the analysis.

2-28 The project objectives were prepared in accordance with CEQA Guidelines §15124 (b) and can be found in Chapter 2, Section 2.2 of the Draft PEA, as follows:

"The objectives of the proposed project are to:

1) *Comply with the requirements in Health and Safety Code (HSC) §§40440 and 39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT;*
2) *Modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment;*
3) *Ensure that RECLAIM facilities, in aggregate, achieve the same emission reductions that would have occurred under a command-and-control approach;*
4) *Achieve the proposed NOx emission reduction commitments in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM; and,*
5) *Achieve NOx emission reductions to assist in attaining the NAAQS."*

The comment that the project objectives do not appear to inform the alternatives and are independent of the proposed project seems to misunderstand the purpose of the project objectives. To repeat line-by-line each element of the project description is not what the project objectives requires. Rather, the project objectives are the foundation upon which the proposed project is based. The proposed project consists of amending the NOx RECLAIM rules in compliance with multiple and complex applicable requirements. The project objectives, cited above, form the framework for crafting the alternatives.

It is important to keep in mind that a CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. In addition, though the range of alternatives must be sufficient to permit a reasoned choice, they need not include every conceivable project alternative (CEQA Guidelines §15126.6 (a)).

As a result, alternatives to the proposed project were crafted by varying how the NOx RTC shave would be applied to the NOx RECLAIM facilities and RTC investors in order to ascertain if there is a project that could meet the project objectives while having lessened impacts than the proposed project. The initial analysis of the proposed project in the NOP/IS determined that, of the amendments proposed, only the components that pertain to the lowered BARCT NOx emission factors could entail physical modifications to the affected equipment and that these physical modifications could create potential adverse significant impacts. As such, in addition to the no project alternative, three alternatives were developed by identifying and modifying major components of the proposed project. Specifically, the primary components of the proposed alternatives that have been modified are the source categories that may be affected, and the manner in which compliance with the proposed lowered BARCT NOx emission factors may be achieved. In addition, in response to comments made by industry, a fifth alternative, with parameters suggested by industry, was also included.

Finally, it is important to note that the reference to Health and Safety Code §39616 has been deleted because it does not require a BARCT analysis. The RECLAIM program proposed here satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so.

2-29 This comment implies that the project is inconsistent with the 2012 Air Quality Management Plan because it goes beyond that control measure's identified 3 to 5 tpd NOx reductions. As explained in Response 2-28, the project proposal needs to meet all five of the project objectives and not just project objective #5 to comply with the initial NOx emission reduction commitment in CMB-01. Furthermore, control measure CMB-01 expressly states that RECLAIM must implement BARCT, so further reductions will be sought if required to attain BARCT. CMB-01 also states that because substantial NOx reductions are needed by 2023, if more reductions are feasible and cost-effective, then they will be considered. (2012 AQMP, Appendix IV-A, Page IV-A-60.) Nothing in CMB-01 limits the rule development efforts to seeking only 3 to 5 tpd.

2-30 This comment asserts that the SCAQMD staff analysis "focused primarily on assessing the maximum number of remaining NOx emissions that could be reduced, to the exclusion of other analyses." California state law defines BARCT as an emissions limitation based on "the maximum degree of reduction achievable" taking into consideration economic impacts. [Health and Safety Code §40406.] Therefore, SCAQMD staff and its consultants examined what BARCT measures could feasibly be implemented, including consideration of costs. Then, after adding allowances for growth, a compliance margin, and BARCT uncertainty, SCAQMD staff set a "remaining emissions" target, and derived the proposed shave as needed to reach that target. SCAQMD staff also prepared a Socioeconomic Report to fully evaluate and disclose the economic impacts of the proposed amendment, and the Draft PEA to disclose the environmental impacts. The fact that the proposed amendments seek more reductions than projected in CMB-01 does not mean cost was not considered. As explained under Area of Controversy Item 5, "The staff proposal is the result of a much more rigorous and in-depth analysis as compared to the analysis that supported control measure CMB-01. For a market-based incentive program, SCAQMD staff is required by the California Health and Safety Code to conduct periodic BARCT reassessments and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment. CMB-01 anticipated this BARCT assessment but could not predict the results of the assessment, and therefore made commitments for a more modest reduction. This staff proposal recommends a reasonably available 14 tpd of NOx RTC reductions, based on BARCT, as required by state law, and the other aforementioned factors. The reduction is also needed to help the Basin achieve the PM2.5 standards by 2019 and 2025 and the ozone standards by 2024 and 2032." As explained in Responses 2-2 and 2-8, the PEA identifies which parts of the proposed project may result in physical effects and the PEA fully analyzes the environmental effects accordingly. This comment asserts that the project has the potential to trigger "unintended consequences" but there is no explanation of such consequences nor evidence to support such a claim.

2-31 Evaluation of the cost-effectiveness of a project is required as part of the rule development process and not CEQA. The $50,000 per ton cost-effectiveness threshold is a criteria applied during rule development to eliminate types of control devices or the application of control equipment for specific equipment before they ever become part of the project. For this reason, cost-effectiveness is not included as a project objective in the PEA because it is an obligation that has to be met as part of formulating a proposal. This comment asserts that the project has a cost which far exceeds that which implementation of BARCT would cost under command-and-control. SCAQMD staff disagrees. The socioeconomic analysis includes a comparison of the costs of implementing the proposed amendments compared to the costs of implementing BARCT under command-and-control, considered on an aggregate basis. At worst, the cost of implementing BARCT-level controls would be the same under RECLAIM as under command-and-control. Because of the flexibility inherent in RECLAIM, it is possible that less costly means to comply will be found. Moreover, RECLAIM has resulted in very substantial cost savings in the past compared to implementing command-and-control.

This comment also asserts that the SCAQMD used a $50,000 cost-effectiveness threshold for the RECLAIM program, while the AQMP used a threshold of $22,500, and the SCAQMD's BACT (Best Available Control Technology) guidance uses a cost-effectiveness of $19,100 per ton. This comment fails to explain how, even if true, this would result in environmental impacts that have not been analyzed, since the Draft PEA assumed that all the identified BARCT controls would be installed, thus resulting in a reasonable worst-case analysis. Moreover, this response compares apples and oranges. The $22,500 threshold in the 2012 AQMP merely triggers more in-depth analysis; it is not a cut-off barring further controls. In BARCT may be more stringent than BACT. See American Coatings Assoc. v. SCAQMD, 54 Cal.4th (2012). See also Response 2-27.

2-32 This comment asserts that the SCAQMD staff used an erroneous useful life when calculating equipment cost-effectiveness. Even if this were true, the comment does not explain how using a different equipment life would result in greater environmental impacts than have already been analyzed. If a shorter equipment life were used, there is the possibility that some controls that were assumed in the draft PEA would no longer be required, thus reducing the potential environmental impacts of the project. Moreover, the comment asserts that the SCAQMD should not use a 25-year useful life because it may amend the RECLAIM rules again in 10 years. While there is always that possibility, there is no evidence to support the assumption that such an amendment would result in having to entirely replace and discard control equipment after only 10 years. Industry has not identified any control equipment that was required to be installed to implement the 2005 RECLAIM amendments that will be discarded as a result of the currently-proposed amendments. It is unlikely that such a result would occur for future amendments. Instead, if a candidate BARCT were identified that would require discarding equipment, that cost would be included in the cost-effectiveness calculation for the candidate BARCT, likely making it no longer cost-effective. As a result, any impacts from future amendments to RECLAIM are speculative, and not a result of the presently-proposed project.

2-33 SCAQMD staff disagrees that Alternative 3 meets all of the project objectives and that the PEA must be recirculated for public review and comment. The proposed NOx RTC shave under Alternative 3 was shown to be substantially less than the proposed project (e.g., 8.77 tpd compared to 14.0 tpd) and the PEA concluded that the entire 8.77 tpd NOx RTC shave could be addressed with unused RTCs without having any facilities modifying their equipment to achieve actual NOx reductions from installing air pollution control equipment. For this reason, Alternative 3 was concluded to not satisfy project objective #2 "to modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment." The Industry Approach (Alternative 3) would not result in achieving the maximum level of reductions achievable and so does not meet the legal requirements under Health and Safety Code §40406, and thus, does not meet all of the project objectives.

2-34 Because of the nature and design of the proposed project, there are multiple criteria with which to comply, as outlined in the project objectives, and the alternatives also must be crafted to attain most of the basic objectives of the project while avoiding or substantially lessening any of the significant effects of the project. In this case, the range of alternatives was constrained by the legal requirement to achieve BARCT-level reductions over the RECLAIM universe in the aggregate. Unlike typical "project objectives" which may be modified at the discretion of the project proponent, the SCAQMD is legally required to implement BARCT for RECLAIM sources. [Health and Safety Code §§40440, 40919.] Therefore, although CEQA allows an alternative to meet "most" project objectives, in this case SCAQMD staff could not consider alternatives that did not at least attain BARCT. While the proposed project, Alternative 1 and Alternative 5 all have the same amount of proposed NOx reductions (e.g., 14 tpd), the distribution of the type of reductions, the manner in which those reductions are achieved, and the type and number of facilities that are affected, are very different. For example, for the proposed project, Alternative 1 and Alternative 5, the 14 tpd reduction would be bifurcated into two parts with: 1) an actual emissions reduction of 8.77 tpd from installing new or modifying existing air pollution control equipment on affected sources as part of the BARCT analysis; and, 2) a reduction of NOx RTC holdings (e.g., a NOx RTC shave) of 5.23 tpd. While the overall total number NOx reductions appear to be the same for each, the facilities in the NOx RECLAIM universe are affected very differently. In particular, for the proposed project, the total 14 tpd of NOx reductions is achieved by applying the NOx RTC shave applied to 90 percent of RTC holders which would only affect 56 facilities. Under Alternative 1, the total 14 tpd of NOx reductions is achieved by applying a 53 percent reduction to all NOx RECLAIM facilities. Finally, under Alternative 5, the total 14 tpd of NOx reductions is achieved by applying a weighted average of the BARCT reduction contribution to all facilities and investors.

As explained in Response 2-8, a CEQA document is not required to consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. In addition, though the range of alternatives must be sufficient to permit a reasoned choice, they need not include every conceivable project alternative (CEQA Guidelines §15126.6 (a)).

By including Alternative 2 with the highest amount of NOx emission reductions and Alternative 3 with the lowest amount of NOx emission reductions, notwithstanding the no project alternative (e.g., Alternative 4), SCAQMD staff believes that a sufficient range of alternatives has been considered and analyzed in the PEA.

2-35 SCAQMD staff disagrees that Alternative 3 is the environmentally superior alternative because even if Alternative 3 has less adverse environmental impacts from construction and operation activities, it achieves much less NOx emission reductions and does not satisfy all of the objectives. This comment claims that the proposed amendments would remove "nearly all of the unused NOx RTCs from the RECLAIM market." This is incorrect. Even after the shave is fully implemented in 2023, there are expected to be over 20 percent of unused RTCs available in the market. Moreover, Alternative 3 does not meet all of the project objectives because it can be almost entirely satisfied by merely surrendering unused RTCs, and not resulting in any substantial actual emission reductions. The Industry Approach, Alternative 3, subtracts 8.77 tpd from the existing number of RTCs, 26.51 tpd, to obtain a remaining emissions amount of 17.72 tpd. This is only 0.51 tpd less than the 18.25 tpd that would have been emitted by RECLAIM facilities at 2005 BARCT, thus gaining only about 0.5 tpd of real emission reductions. While there is the potential that facilities may install some additional controls, and thus, attain some additional reductions, in order to maintain a "compliance margin" of RTCs, there is no reason to assume that the facilities would not give up any of the large amount of excess RTCs under Alternative 3. Therefore, this proposal does not demonstrate why additional reductions are not achievable, and thus, does not meet the legal requirements for implementing BARCT.

By taking into consideration the amount of the shave that would be applied by each of the alternatives as an indicator of how facility operators may respond to the reduced amount of available NOx RTCs in the market, then Alternative 2 would have the greatest chance of ensuring that all control equipment that is contemplated would be installed in order to ensure that the maximum amount of NOx emissions reductions projected would actually occur. For this reason, Alternative 2 was selected by staff as the environmentally superior alternative. Although this alternative would have the greatest amount of impact from construction and operation of control equipment, the overall impact to the environment over the long term is highly beneficial by inducing greater NOx reductions. The comment letter seems to incorrectly assume that a lead agency cannot consider the environmental benefits of a project when identifying the environmentally superior alternative.

2-36 As explained in Response 2-25, the PEA contains a program level analysis of the potential effects of the proposed project but also anticipates future activities. The PEA acknowledges that implementation of the proposed project may result in the construction and operation activities that may cause environmental impacts for some facilities. However, it is also possible that these same facilities may already have sufficient NOx RTCs available or may choose to purchase more NOx RTCs to comply with the proposed project instead of installing new or modifying existing air pollution control equipment. As explained in the alternatives analysis in the Chapter 5 of the PEA, Alternative 3, by only having to achieve 8.77 tpd of RTC reductions instead of 14 tpd, less environmental impacts would be expected to occur because fewer construction projects and corresponding operation activities would be needed to achieve the overall emission reduction goal. Further, with fewer construction and operation activities, the resulting environmental impacts would also be lesser. However, it is not necessarily the case that the projects foregone would always be those which use ammonia. While the comment letter asserts that the likely NOx emission control projects can be quantified, it does not provide any evidence as to which specific projects would be foregone. While cost-effectiveness may provide a reasonably foreseeable projection of potential future compliance activities which were analyzed in the PEA, to determine which construction projects would go forward and which would not in order to further define which specific environmental topic areas would be reduced, would require speculation which is prohibited by CEQA.

2-37 This comment claims that the Draft PEA did not explain why the proposed project will only result in 8.77 tpd emission reductions when history suggests a one-to-one ratio between RTC reductions and program emission reductions. SCAQMD staff disagrees that any such fixed ratio exists. For example, if the years 2007-2011 are considered (implementation of the 2005 NOx shave), RTCs were reduced by 7.66 tpd, while emissions were reduced only 4.09 tpd, for a ratio of 0.53 ton of emissions reduced for every ton of RTCs reduced. The Draft PEA accounted for the fact that if RTCs are not significantly reduced, there will be enough excess RTCs in the market that facilities can simply surrender unused RTCs, without making significant real emission reductions. For a discussion of why the Industry Approach (Alternative 3) does not meet BARCT, see Response 2-35.

This comment claims that Alternative 3 meets 8.77 tpd of emission reductions and attains BARCT, but does so with fewer environmental impacts. SCAQMD staff disagrees. Alternative 3 would not obtain the same emission reductions as the proposed project unless it is assumed that industry would not give up any of the excess unused RTCs in the market, and instead would install exactly the same controls as they would under a 14 tpd shave. Industry has not provided any substantial evidence that facilities would not give up excess unused RTCs, especially since the current value of RTCs (less than $4,000 per ton) is substantially less than the average cost of control for the proposed shave ($13,615 per ton as stated in the Draft Final Socioeconomic Report, Table 7, page 13).

The adverse environmental impacts of Alternative 3 would be equivalent to the proposed project only if all 8.77 tpd of NOx emission reductions are achieved from installing new or modifying NOx air pollution control equipment. As explained in Response 2-36, it is possible that the affected facility operators may already have sufficient NOx RTCs available or may choose to purchase more NOx RTCs to comply with the proposed project instead of installing new or modifying existing air pollution control equipment. Thus, because Alternative 3 has less incentive to reduce actual NOx emissions and instead has a higher likelihood of achieving “paper emission reductions” by relying on unused RTCs rather than having control equipment installed, Alternative 3 does not qualify as the environmentally superior choice. Moreover, even in the highly unlikely event that Alternative 3 resulted in the same actual emission reductions as the proposed project, by installing and operating control equipment, it would have the same environmental impacts as the proposed project and would thus not be environmentally superior.

2-38 See Response 2-28, and Responses 2-35 through 2-37.

2-39 The staff proposal for the rule amendments used established industry-specific growth factors to project RTCs needed for all RECLAIM sectors, including electricity generating facilities (EGFs), and included these needs in the remaining emissions target for the shave. The growth factors used in the analysis were provided by the Southern California Association of Governments and are the same as used in the 2012 AQMP, except for electricity generating facilities which used a growth factor from the 2014 California Gas Report (see Appendix W of the Revised Draft Staff Report, pp. 217-218).

The staff proposal has been refined over recent months to address many of the concerns that stakeholders have raised. The staff proposal contains several safeguards that would provide EGFs with an adequate amount of credits, while concurrently achieving the objective of the proposal, which is to effect the installation of BARCT for the applicable equipment categories identified. The safeguards include access to non-tradable/non-usable RTCs with a faster 3-month trigger. The 12-month trigger remains, but the threshold level is now $22,500 per ton. In the event of a State of Emergency declared by the Governor, EGFs would have access to non-tradable/non-usable credits. If these credits are exhausted, EGFs would also have access to the credits in the Regional NSR Holding Account. Furthermore, EGFs now have the option to exit the RECLAIM program if they meet certain requirements. Under this option, an EGF would no longer be concerned with the possibility of an RTC shortage, even though staff believes that there will not be a shortage if BARCT controls are implemented for those applicable facilities that were analyzed. Finally, the SCAQMD staff will propose a Governing Board Resolution which directs SCAQMD staff to monitor the increased demand for electricity, and the needs of electricity generating facilities in RECLAIM and report to the Governing Board or Stationary Source Committee, as appropriate. With these safeguards in place, no adverse impact on electrical reliability is anticipated, so there would be no resulting adverse environmental impacts. See also Responses 2-21 and 2-22 regarding RECLAIM facilities that are no longer in operation.

2-40 Contrary to the comment, Chapter 4, Subchapter 4.3 of the PEA, contains an energy impact analysis which identifies the net effect on energy resources relating to the construction and operation of new or modified NOx air pollution control equipment that may occur as a result of implementing the proposed project. See also Responses 2-21, 2-22, 2-39, 4-5 and 6-3.

2-41 The projected increased use of ammonia by 39.5 tpd does not mean that 39.5 tpd of ammonia will be emitted into the atmosphere. If that were the case, the injection of ammonia into SCR units would be rendered useless for reducing NOx emissions. Rather, the projected increased use of ammonia by 39.5 tpd represents the amount injected into the flue gas streams by all the potential SCRs needed to reduce NOx. While most of the ammonia reacts with the NOx to form elemental nitrogen (N_2) and water in the cleaned exhaust gas, there is a small amount of unreacted ammonia (ammonia slip) that also passes through. SCAQMD staff conducted a series of regional simulations to determine the impacts of reducing NOx by the proposed RTC shave while increasing the potential for creating ammonia slip due to increased use of ammonia needed for the operation of SCR controls. In the analysis, NOx emissions were reduced at RECLAIM facilities by a total of 14 tpd while increasing ammonia slip emissions from the same facilities by 1.63 tpd. The simulations were run for the 2021 draft baseline emissions inventory to estimate the impact when full implementation of the RECLAIM shave was expected to be achieved. The effect of decreasing 14 tpd of NOx would result in a decrease of annual PM2.5 of approximately 0.7 $\mu g/m^3$. However, since ammonia is necessary to achieve the 14 tpd of NOx emission reductions, the use of ammonia would cause a concurrent increase in annual PM2.5 of approximately 0.6 $\mu g/m^3$. Thus, increasing the amount of ammonia slip would result in net average 0.1 μg/m^3 decrease in annual PM2.5. Further, simulations showed that no change in ozone would be expected compared to what would occur with no increase in ammonia slip. The overall decrease in annual PM2.5 would occur provided that all 14 tpd of NOx emissions will be reduced, which in turn would reduce PM2.5 emissions overall, even if some PM2.5 emissions are generated from ammonia slip. In summary, the impacts to regional PM2.5 and ozone due to increased ammonia slip in the simulations would not create a significant impact.

This comment also asserts that the analysis should have used 20 ppm ammonia slip from SCRs rather than the 5 ppm required by SCAQMD permits because existing SCRs may not have that permit condition. However, existing SCRs, except for one, are not part of the proposed project and therefore, are not part of the environmental impacts of the proposed project. One existing SCR is expected to use increased catalyst as a compliance mechanism, but all other projected SCRs are new. For these reasons, the health risk analysis for ammonia in the PEA does not need to be revised.

2-42 The Draft PEA considered potential hazards impacts that were reasonably foreseeable at the time of its preparation for both accidental and non-accidental releases, Relative to accidental releases, an ammonia analysis was conducted in Chapter 4, Subchapter 4.3 of the PEA which addresses both an ammonia transportation spill scenario and two ammonia tank rupture scenarios (non-refinery and refinery). The analysis concluded that only ammonia transportation activities could potentially cause significant adverse hazards and hazardous materials impacts.

Relative to non-accidental releases (e.g., operational emissions or concentrations), the analysis in the PEA relies on SCAQMD Rule 1401 – New Source Review of Toxic Air Contaminants, which by design, prevents significant adverse environmental impacts. In order for a facility to install control equipment that requires ammonia use and storage for its operation, the facility operator will need to submit a permit application which will undergo an analysis in accordance with Rule 1401 to determine the increases, if any, in the maximum individual cancer risk (MICR), cancer burden, and chronic and acute hazard indices. The SCAQMD's CEQA significance thresholds allow any project that will comply with Rule 1401 to be considered to have a less than significant impact.

Further, ammonia slip is limited to 5 ppm concentration by permit condition for each new or modified permit unit. Based on the June 2015 Staff Report for SCAQMD Rule 1401.1 – Requirements for New and Relocated Facilities Near Schools, and SCAQMD Rule 1402 – Control of Toxic Air Contaminants from Existing Sources, the concentration at a receptor located 25 meters from a stack would be much less than one percent of the concentration at the release from the exit of the stack. Thus, the peak concentration of ammonia at a receptor located 25 meters from a stack is calculated by assuming a dispersion of one percent. So even if multiple SCRs are installed at one facility, each SCR would be limited to a concentration of 5 ppm ammonia slip which would pass the Rule 1401 requirements. When calculating risk, concentrations (mass per volume) are not additive. Multiple adjacent stacks generating 5 ppm ammonia concentrations from ammonia slip would still only result in a total maximum ammonia concentration of 5 ppm, which based on the analysis in the PEA, is not expected to cause an offsite risk.

Finally, each affected refinery is subject to the Air Toxics "Hot Spots" Information and Assessment Act in accordance with the California legislature's AB2588 program. Under AB2588, facilities are required to submit an air toxics inventory through the SCAQMD's Annual Emissions Report (AER) Program and potentially high risk facilities must prepare a health risk assessment (HRA). If the risk reported in the HRA exceeds specific thresholds, then the facility is required to provide public notice to the affected community. Facilities with health risks above the action risk levels in Rule 1402 must reduce their risks to the community.

Of course, if site-specific characteristics and circumstances are involved with future projects to install NOx control equipment that utilize ammonia that are outside the scope of this analysis, a further facility-specific ammonia hazards analysis may be warranted. This information will be considered as part of the future project level CEQA review to determine if new or worsened impacts will occur when compared to what was analyzed in the PEA.

2-43 This comment notes that SCAQMD staff identified a potential control measure for the 2016 AQMP to reduce ammonia slip from NOx controls. Even if this measure is ultimately included in the 2016 AQMP, the proposed RECLAIM amendments are not inconsistent with such a measure. The socioeconomic analysis of the staff proposal does not anticipate actual installation of controls until 2018 or later[8], which would provide sufficient time to adopt and incorporate any new ammonia control measure into the permits issued for NOx controls under RECLAIM. Moreover, even if there were increased ammonia slip that creates increased PM2.5, that would not mean the project as a whole has an adverse impact on the environment, but only that the expected PM2.5 benefits might be lessened. For a discussion of ammonia slip impacts, see Response 2-41.

2-44 CEQA Guidelines §15155 – City or County Consultation with Water Agencies, defines a "water-demand" project in several ways. While the criteria for defining water demand are not significance thresholds per se, the criteria in this section provides some insight as to how water purveyors or city or county lead agencies evaluate water-demand impacts. Note that the SCAQMD does not qualify as a water purveyor or a city or county lead agencies under this part.

Nonetheless, the analysis in CEQA documents needs to make a significance determination relative to water demand. Most of the criteria in CEQA Guidelines §15155 do not have a bright line or direct way to correlate the criteria in terms of gallons per day (gal/day) in order for SCAQMD staff to determine what a water demand project would

[8] SCAQMD, Revised Draft Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), October 6, 2015, Table 8, p. 15. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/reclaim_revisedsociodraft.pdf?sfvrsn=2

be. As such, in 2008, SCAQMD staff examined CEQA Guidelines §15155 (a)(1)(C) which defines a water-demand project as: "A commercial office building employing more than 1,000 persons or having more than 250,000 square feet of floor space" and estimated what this means in terms of water demand per person relative to the square footage (sf) of the floor area of the plant[9], commercial water usage rates[10] and average employment levels[11] (i.e. the number of employees per square foot) can be applied as follows:

Commercial Water Usage in California in Year 2000:

$$\frac{\text{1,850,000 ACRE FEET WATER}}{\text{YEAR}} \times \frac{\text{325,851 GALLONS}}{\text{1 ACRE FOOT WATER}} \;/\; \text{4,920,114 X 10}^{3}\text{ FT}^{2}\text{ OF COMMERCIAL FLOOR STOCK} = \text{123 GALLONS WATER PER YEAR PER FT}^{2}\text{ OF COMMERCIAL FLOOR STOCK}$$

$$\frac{\text{123 GAL WATER}}{\text{(YEAR) (FT}^{2}\text{ OF BUILDING)}} \times \frac{\text{1,000 FT}^{2}\text{ OF BUILDING}}{\text{1.8 EMPLOYEES}} \times \frac{\text{1 YEAR}}{\text{260 DAYS}} \times \text{1,000 EMPLOYEES} = \text{262,820 GAL/DAY}$$

This water demand estimate was then applied to industrial sources because CEQA Guidelines §15155 (a)(1)(E) uses the same 1,000 employee level to defines a water-demand project as: "An industrial, manufacturing, or processing plant or industrial park planned to house more than 1,000 persons, occupying more than 40 acre of land, or having more than 650,000 square feet of floor area." Because the potable water demand calculation based on 1,000 employees is more in line with industrial applications, the potable water demand significance threshold currently in effect is 262,820 gal/day.

The PEA conducts a program level analysis that relies on this potable water significance threshold. The PEA estimates the projected increases in water demand for hydrotesting and operational activities for each affected facility. See Chapter 4, Subchapter 4.5, Tables 4.5-6 through 4.5-8 for hydrotesting water demand and Tables 4.5-9 and 4.5-10 for operational water demand.

Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the installation of WGS technology along with the corresponding increased water demand and wastewater generation projections that were originally contemplated for one of the two FCCUs (e.g.,

[9] California Commercial End-Use Survey, Consultant Report, Table 8-1 Page 150. Prepared For: California Energy Commission, Prepared By: Itron, Inc., March 2006. http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.PDF

[10] Peter H. Gleick, Dana Haasz, Christine Henges-Jeck, Veena Srinivasan, Gary Wolff, Katherine Kao Cushing, and Amardip Mann, "Waste Not, Want Not: The Potential for Urban Water Conservation in California", Executive Summary, Table ES-1, Pacific Institute, November 2003. http://www.pacinst.org/reports/urban_usage/waste_not_want_not_full_report.pdf

[11] Urban Land Use Institute Data, Wausau West Industrial Park Expansion, Development Impact Analysis, Average Employment Levels, p.4, Prepared by Vierbicher Associates, January 5, 2001. http://www.ci.wausau.wi.us/mwg-internal/de5fs23hu73ds/progress?id=8YbqRwayH6il518Xi6htHpaWUGVUTPrZJDZ0BKzTvlY,&dl

Refineries 4 and 9) identified in Tables 4.5-9 and 4.5-10 are no longer expected to occur. Thus, the potential increase in water demand needed for the operation of WGS technology is expected to be less than what was previously analyzed and will affect six of the seven refineries. To protect the identity of the refinery in this document, Subchapter 4.5 of this PEA has been revised to reflect that the potential increase in operational water demand will range from 553,499 gal/day to 558,978 gal/day, instead of 602,814 gal/day as shown in Table 4.5-9. While this range still exceeds the potable water demand significance threshold of 262,820 gal/day, there are several circumstances that lead SCAQMD staff to believe that most of this water demand may be supplied with recycled water instead.

Because of the drought and the uncertainty of future water supplies, it was not clear at the time of the release of the Draft PEA whether water suppliers would be able to accommodate the additional operational water demand if the proposed project goes forward, especially if potable water would be relied upon to supply the water demand. Subsequently, SCAQMD staff has been able to verify that projected water deliveries of potable water and recycled water to industrial sources will be able to supply the potential water demand needs of the proposed project. As part of making a determination if water supplies will be sufficient for the proposed project, the availability of recycled water is an important factor. For example, as explained in Subchapter 4.5, Refineries 1, 5 and 6 currently access recycled water from the Harbor Refineries Recycled Water Pipeline (HRRWP) which is maintained by the Los Angeles Department of Water and Power (LADWP), in conjunction with the West Basin Municipal Water District (WBMWD). The LADWP/WBMWD currently provides 35 million gallons per day (MMgal/day) of recycled water to its customers, which include Refineries 1, 5, and 6. The WBMWD is also in the process of expanding its Hyperion Pump Station to accommodate a throughput of 70 MMgal/day of source water which would result in about 55 to 60 MMgal/day of saleable recycled water if, and when needed to accommodate any increased need by their customers[12]. When operators of these three refineries utilize recycled water in lieu of potable water to satisfy the water demand for the NOx control equipment that may be installed in response to the proposed project, then the LADWP/WBMWD would be able to supply the additional water (e.g., 398,767 gal/day or approximately 71 percent of the total projected water demand) to these three refineries. A mitigation measure is proposed that would effectively require these operators to use recycled water.

At the time of writing the Draft PEA, SCAQMD staff was not able to confirm whether three refineries (e.g., Refineries 4, 8 and 9) have connected to the HRRWP to access its supply of recycled water. To date, none of these refineries have connected to the HRRWP. However, Refinery 4 is in the process of finalizing an agreement with WBMWD to acquire 2,240 acre-feet/year (AF/yr)[13] of recycled water (equivalent to two MMgal/day) to replace its current potable water use with recycled water by 2018. In addition, Refineries 4, 8, and 9 are also currently in talks with LADWP to negotiate options for replacing as much as 11,100 AF/yr (equivalent to approximately 9.9

[12] Personal communications with Uzi Daniels and Joe Walters, West Basin Municipal Water District, August 3, 2015 and November 4, 2015.

[13] 1 acre-foot = 325,851 gallons

MMgal/day) of current potable water use with recycled water instead via the HRRWP[14]. Thus, if Refineries 4, 8 and 9 need additional recycled water in response to this proposed project, the LADWP/WBMWD has the capacity to provide additional recycled water as necessary[12]. If recycled water is not available at these refineries, then potable water is also available.

Further, Refinery 2 is not located near the HRRWP nor any other recycled water pipeline so it is unlikely that Refinery 2 would be able to obtain recycled water should facility operators choose to install a WGS and instead, would need to satisfy the water demand with potable water. According to the Long Beach Water Department's (LBWD's) 2010 UWMP that was prepared in accordance with the California Water Code §10608.20, the potable water delivery projections to their industrial and commercial customers show a long-term projected increase in potable water supply with a slight tapering occurring in years 2030 and 2035 to reflect offsetting by increased deliveries of recycled water to other customers currently being supplied by LBWD with potable water (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, Table 4.5-18, p. 4.5-20. Based on LBWD's short- and long-term projections for potable and recycled water supplies, SCAQMD staff believes that the potential increased water demand of 40,896 gallons per day for Refinery 2 can be accommodated.

In addition, it is important to keep in mind that operators of Refinery 2 have two different types of control equipment options available for consideration. As summarized in Tables 1-2 and 1-3 for the petroleum coke calciner source category, the BARCT NOx levels of 10 ppmv corrected for 3% oxygen can be achieved with either a WGS which uses water, or a DGS, which does not. While the analysis in this subchapter considers the technology with the worst-case impacts to water demand and water quality, for Refinery 2, installing WGS technology is not their only option. Should operators choose to install a DGS, instead of a WGS, then no water would be needed.

Thus, while the amount of water demand that would be needed to operate NOx control equipment would be 398,767 gallons per day at Refineries 1, 5 and 6 and the amount of water demand at Refineries 2, 4, 8, and 9 would be in the range of 113,836 gallons per day to 160,211 gallons per day, which collectively is greater than the significance threshold of 262,820 gallons per day of potable water but less than the significance threshold of five million gallons per day of total water (e.g., potable, recycled, and groundwater), in consideration that Refineries 1, 5 and 6 have a high potential to use recycled water because of their current access and in light of the negotiations for recycled water at Refineries 4, 8, and 9, potable water only may be needed for a future project occurring at Refinery 2, or not at all if operators of Refinery 2 choose to install a DGS instead of a WGS. In any case, the previous analysis shows that water purveyor would be able to supply potable water to Refinery 2 and to Refineries 1, 4, 5, 6, 8 and 9, if needed. Thus, using an abundance of caution, because the peak daily water demand for the

[14] City of Los Angeles, Inter-Departmental Correspondence to City Council From Los Angeles Department of Water and Power and Los Angeles Department of Public Works Bureau of Sanitation, Council File No. 15-0018 Harbor Refineries Pipeline Project/Advanced Water Purification Facility/Water Supply Efforts, April 10, 2015. https://cityclerk.lacity.org/lacityclerkconnect/index.cfm?fa=ccfi.viewrecord&cfnumber=15-0018

proposed project exceeds the potable water threshold of 262,820 gallons per day and because recycled water is not currently available at Refineries 4, 8 and 9, and no contractual commitments to increase recycled water demand above the existing recycled water baseline for the three refineries that already have access to recycled water (e.g., Refineries 1, 5 and 6) have been finalized, the analysis conservatively assumes that significant adverse impacts associated with water demand are expected from the proposed project during operation.

In general, in order for a facility to install control equipment, the facility operator will need to submit a permit application to the SCAQMD which will undergo a CEQA pre-screening analysis to determine if the project complies with the analysis in the PEA and whether or the project can rely on the PEA or if an additional CEQA document would be required. If water is required for conducting hydrotesting and for operating air pollution control equipment that utilizes water, then the project would be subject to mitigation measures (e.g., HWQ-1 and HWQ-2 for hydrotesting and HWQ-3 and HWQ-4 for operation of air pollution control equipment that utilizes water) which will be incorporated into the permits for enforceability purposes.

For any facility that will need to conduct hydrotesting, mitigation measures HWQ-1 and HWQ-2 require facility operators to utilize both current supplies and future supplies of recycled water in accordance with the California Water Code, and if available, pursuant to the HRRWP or other recycled water pipeline, if available, to conduct hydrotesting. Alternately, facility operators may substitute the use of purchased recycled water with non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility. See Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, pp. 4.5-10 – 4.5-11.

Similarly, for any facility that installs air pollution control equipment that utilizes water such as WGS as part of the proposed project, mitigation measures HWQ-3 and HWQ-4 require facility operators to utilize both current supplies and future supplies of recycled water in accordance with the California Water Code, and if available, pursuant to the HRRWP or other recycled water pipeline, if available, for operation of that air pollution control equipment. See Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, p. 4.5-23.

These mitigation measures will, if implemented, be effective in reducing the overall demand on potable water, to a less than significant level. It is important to note that if the amount of water needed for each individual project exceeds from the quantities disclosed in the PEA, then a revised water supply assessment may be necessary.

Finally, Subchapter 4.5 of the PEA has been revised to identify the various suppliers of purchased potable and recycled water for the affected facilities and the water suppliers projected supply estimates based on each water supplier's UWMPs. In conclusion, the water demand analysis and conclusions in the PEA has been based on the best available information.

2-45 As explained in Response 2-13, the analysis in the Draft PEA relies on data and methodologies from previous CEQA documents such as the Final EA for NOx RECLAIM that was certified in January 2005 and the Final PEA for SOx RECLAIM that was certified in November 2010, for example. The NOP/ISs prepared for these projects address the potential noise impacts for refineries and other affected non-refinery facilities in a similar manner as the currently proposed project and noise impacts were concluded to be less than significant at the NOP/IS stage. The noise analysis in the NOP/IS for the proposed project was based on best available information for a program level analysis and no concerns were raised relative to noise during the NOP/IS comment period. For this reason, the PEA did not further analyze noise impacts beyond what was contained in the NOP/IS. If and when each actual construction project is proposed as a result of complying with the proposed project, each individual facility operator will have to comply with the local noise element and ordinances applicable to their facility location during both construction and operation after build-out. Thus, less than significant noise impacts would be expected.

2-46 Chapter 4, Subchapter 4.6 of the PEA contains an analysis of the potential solid and hazardous waste impacts that may occur as a result of implementing the proposed project. The significance criteria for determining whether solid and hazardous waste impacts would be significant are based on whether the generation and disposal of hazardous and non-hazardous waste would exceed the capacity of designated landfills. The analysis in the PEA examined the potential volume of operational waste that would either be recycled or disposed of, and concluded that the amount, if disposed of, would not exceed those capacity levels; indeed it is a very small (7.61 tpd) amount relative to the capacities of the 31 Class III landfills and two transformation facilities (107,933 tons per day and day and 3,240 tons per day, respectively). In addition, as explained in Chapter 4, Subchapter 4.6, due to the heavy metal content and its relatively high cost, catalyst recycling, in lieu of disposal, can be a lucrative and likely preferred choice of facility operators. If recycling is utilized, the estimated impacts to solid waste would be less than what was analyzed in the PEA.

It is important to keep in mind that landfills undergo their own separate CEQA analysis as part of their permitting process, whether to continue to operate, extend closure dates, or expand operations, and this analysis already considers the impacts on the nearby communities. Thus, the suggestion to evaluate the impact of communities that are located near hazardous waste landfills, is not necessary nor required to be included in the PEA.

Regarding the use of increased ammonia to operate SCR technology, see Responses 2-41 and 2-42.

2-47 As explained in Responses 2-21 and 6-5, the past reduction in the number of facilities that participate in the NOx RECLAIM program over the years from 392 to 275 is not a product of the proposed project that would require an analysis in this PEA. The comment also asserts that the PEA did not adequately analyze the growth-inducing impacts of the project, and that the PEA did not explain the source of the growth factors used, and that the PEA should consider a scenario which allows for more growth of RECLAIM facilities, and modify the growth-inducing impacts accordingly. The growth factors used in the analysis were provided by the Southern California Association of Governments and are the same as used in the 2012 AQMP, except for electricity generating facilities which used a growth factor from the 2014 California Gas Report (see Appendix W of the Draft Staff Report, pp. 217-218). Even if the economy grows more than projected so that the RECLAIM facilities also grow more than projected, this would not be a result of the proposed RECLAIM amendments but of independent factors in the economy. CEQA only requires consideration of the growth-inducing aspects of the project. The only potential growth inducing impact identified was an increased need for construction workers during the installation of controls. This impact was fully analyzed in the PEA (see Chapter 4, Subchapter 4.8, pp. 4.8-10 to 4.8-13).

2-48 The SCAQMD's mission statement is based on the concept that all who live or work in this area have a right to breathe clean air. The SCAQMD is committed to undertaking all necessary steps to protect public health from air pollution, with sensitivity to the impacts of its actions on the community and businesses. This is accomplished through a comprehensive program of planning, regulation, compliance assistance, enforcement, monitoring, technology advancement, and public education.

Further, when it comes to conducting a CEQA analysis for proposed projects, including amending rules and regulations as is the case with this project, CEQA Guidelines §15021 establishes a duty for all public agencies to avoid or minimize environmental damage where feasible and this duty is implemented through the findings requirements in CEQA Guidelines §15091. The findings, as well as the Statement of Overriding Considerations and mitigation monitoring plan, are included as an attachment to the Resolution of the Governing Board package.

The SCAQMD staff believes that the PEA has fully identified and analyzed the potentially significant adverse impacts of the proposed project and that the commenter has not presented any new evidence that would warrant the addition of new information to the PEA that would require recirculation of the PEA for an additional public review and comment period.

2-49 The NOP contained the following general overview of the nature, description and beneficiaries of the proposed project which clearly states in the underlined text below that the SCAQMD intended to shave available RTCs:

> *"SCAQMD staff is proposing amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to reduce the allowable NOx emission limits based on current Best Available Retrofit Control Technology (BARCT) to achieve additional NOx emission reductions for the following industrial equipment and processes: 1) fluid catalytic cracking units (FCCUs); 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units (SRU/TGUs); 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7)*

non-refinery/non-power plant internal combustion engines (ICEs); 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RECLAIM Trading Credits (RTCs) and NOx RTC adjustment factors for year 2016 and later. For clarity and consistency throughout the regulation, other minor changes are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions; and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions. The Initial Study identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Impacts to these environmental areas will be further analyzed in the Draft Program Environmental Assessment (PEA)." [emphasis added]

Similar statements expressing this same intention were also made in the IS on pages 1-2 and 1-7, for example. It is important to keep in mind that the project description in the PEA reflects updates to the project that occurred during the rule development process and as such, the version that was in the Draft PEA was not identical to the description in the NOP. The project description in the Draft PEA represented an updated version of the project at the time and superseded the project description in the NOP. Similarly, the project description in the Final PEA has been further revised since the release of the Draft PEA, and now contains the final version of the project.

If the commenter has interpreted "modify the RTC shaving methodology" to mean that a necessary part of the project is to change from an across-the-board shave to a shave more targeted to the sources that have new BARCT controls available, this was not the intent of the statement. While staff believes that a targeted shave is more equitable, and was used in the 2010 SOx RECLAIM amendments, the PEA presents alternatives for the Governing Board's consideration that include an across-the-board shave.

2-50 This comment asserts that a 14 tpd shave is not necessary and may violate Health and Safety Code §40406 which requires consideration of economic factors in setting BARCT levels. Staff disagrees. For a discussion of why the 14 tpd shave is necessary, see Responses 2-35 and 2-37. Moreover, the Preliminary Draft Staff Report, Draft Staff Report, and Revised Draft Staff Report clearly explain that the staff considered economic factors in establishing the new BARCT levels for the individual categories of sources, to arrive at a level of remaining emissions that would occur if facilities at 2011 activity levels were to implement 2015 BARCT. Staff then further considered economic factors by adding a growth factor, a compliance margin, and an allowance for BARCT uncertainty to the target remaining emission levels. Finally, the socioeconomic impact analysis considered all the costs of compliance with the proposed amendments, and all of the CEQA alternatives.

This comment also asserts that the proposed amendments violate Health and Safety Code §39616 (c)(1) because they do not produce equivalent or more emission reductions at equivalent or less cost than command-and-control, since they use a higher cost-effectiveness threshold than the threshold stated in the AQMP, they go beyond BARCT, and the findings of Norton Engineering would further reduce the amount of emission reductions. The socioeconomic analyses conducted for the RECLAIM program proposed here satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so. For a discussion of the cost-effectiveness threshold, see Response 2-31. All of these comments are addressed in Appendix Z to the Revised Draft Staff Report. For a discussion of BARCT and equivalency to command-and-control, see Appendix Z, Response 1-5. For an explanation of how Norton Engineering results were addressed in the staff proposal, see Appendix Z, Response 1-6.

This comment also asserts that the staff proposal results in disproportionate impacts, because RECLAIM sources have reduced their emissions by a greater percentage than command-and-control sources since 1994. This does not mean that there are disproportionate impacts. As long as all sources are subject to BARCT, the maximum achievable reductions for that category of source - then all sources are being treated equally, regardless of whether the percent reductions are the same. There are many reasons why some source categories cannot attain the same percent reductions as other categories. For a discussion of the alleged disproportionate impact, see Appendix Z, Response 1-9. Also, the SCAQMD has adopted command-and-control rules with similar percent reductions and cost-effectiveness as are involved in this proposed amendment. For example, Rule 1146 (applies to large boilers and heaters) projected a 65 percent reduction in emissions with a cost-effectiveness ranging from $10,000 to $32,000 per ton. Rule 1146.1 (applies to small boilers and heaters) projected a 71 percent reduction in emissions with a cost-effectiveness of $14,000 to $33,500 per ton. Finally, Rule 1110.2 (applies to engines) projected a 74 percent reduction in emissions with a cost-effectiveness ranging from less than $100 up to $28,000 per ton.

This comment states that the BARCT levels selected for the source categories have not been demonstrated to be broadly achievable. However, Norton Engineering and SCAQMD staff ultimately agreed on the BARCT levels for all categories except refinery boilers and heaters, for which SCAQMD staff made an adjustment in the remaining emissions target. This comment also states that the BARCT levels go well beyond the rules adopted under SCAQMD Regulation XI – Source Specific Standards. However, the proper comparison is what level of BARCT would have been required by the SCAQMD for these same source categories under command-and-control rules, not what has been required for other Regulation XI source categories. The comment also states that the BARCT levels go beyond what is required in other air districts, but provides no supporting data, examples, or citations as evidence. Finally, the comment fails to explain how any of these issues would affect the environmental impacts of the project, which already assume that all the identified BARCT controls would be installed.

2-51 While it is correct that the BARCT analysis focuses on these equipment categories, the paragraph goes on to say: "*Additional amendments are proposed to establish procedures* *and criteria for reducing NOx RECLAIM RTCs and NOx RTC adjustment factors for year 2016 and later. Other minor changes are proposed for clarity and consistency throughout the proposed amended regulation."* Thus, the proposed project is not solely limited to the BARCT analysis. See also Responses 2-2 and 2-8.

Moreover, facility operators may choose to use existing RTCs or purchase additional RTCs in lieu of implementing any of the various control technologies analyzed in the PEA, if they find that doing so would be more cost-effective. While cost-effectiveness may provide a reasonably foreseeable projection of potential future compliance activities which were analyzed in the PEA, staff does not have a way of predicting which approach facilities will actually choose, nor does the comment suggest what facilities might do instead. For these reasons, the analysis in the PEA contemplates a combination of potential future activities, without knowing all of the actual details of individual projects that would be undertaken in the future by facility operators. See also Response 2-16.

2-52 See Response 2-28.

2-53 This comment states that the proposed amendments would result in a level of "unused" RTCs that has only been seen during the power crisis of 2000-2001. This comment is not accurate. Even after full implementation in 2023, the proposed amendments would result in a level of unused RTCs that is over 20 percent greater than expected emissions, i.e. 12.51 tpd RTCs compared to 10.21 tpd expected emissions (2.3 divided by 10.21 = 22 percent). WSPA, as part of the Industry Coalition, stated at the Special Stationary Source Committee held on October 16, 2015, that historically, the amount of unused RTCs, not including during the power crisis, had varied from 15 percent to 30 percent. Thus, because the proposed amendments would result in a 22 percent margin which is within the historical range, this topic does not qualify as a new area of controversy that needs to be added to Table 1-1 in the PEA.

2-54 This comment is a repeat of the sentiments expressed in the August 27, 2015 letter, Comment 1-20. See Revised Draft Staff Report, Appendix Z, Response 1-20, p. 284.

This comment asserts that there continues to be a significant number of unresolved issues related to the analysis by Norton Engineering. For a discussion of how staff accounted for the Norton Engineering analysis in the staff proposal, see Appendix Z to the Revised Draft Staff Report, Response 1-6. This comment also says that staff's adjustment for the one area in which its analysis continues to differ from that of Norton Engineering is improper. The difference between Norton Engineering's approach and staff's approach resulted in a difference of 0.33 tpd emissions. Staff accounted for that difference and more by subtracting 0.79 tpd from the amount of the RTC shave (i.e., increasing the allowable remaining emissions to 12.51 tpd). This comment asserts that instead, the adjustment should have been made from the BARCT level. Under staff's methodology, which establishes a remaining emissions goal, reducing the amount of the shave has the same effect as reducing the BARCT goal - in both cases the allowable remaining emissions are increased. Whether the adjustment is subtracted from the shave amount or the BARCT goal only makes a difference if the Industry methodology is used. See also

Response 2-10. For a discussion of why the Industry proposal does not meet BARCT requirements, see Response 2-35.

2-56 This comment asserts that the PEA does not support the assertion that 14 tpd must be shaved to obtain 8.77 tpd actual emission reductions, and that under the 2005 shave, a 23 percent reduction in RTCs resulted in a 24 percent reduction in emissions. See Response 2-37.

2-57 This comment claims that the staff has not explained how its proposal complies with Health and Safety Code §40406 because it does not consider economic impacts from reductions that go beyond BARCT, and does not show how the proposal results in equivalent or greater emission reductions at equivalent or less cost than would occur under command and control. These issues are addressed in the Draft Final Socioeconomic Impact Report, in particular see the section that compares the proposed project to command-and-control (Section 10). For a discussion of the assertion that the proposal goes beyond BARCT, see Responses 2-35 and 2-37 that explain why the industry proposal does not satisfy BARCT, and how the SCAQMD's proposal does not go beyond BARCT.

2-58 This comment asserts that staff's proposal for an NSR adjustment account for power plants does not apply to new facilities and that it needs to demonstrate how the proposal would comply with EPA requirements. As to the latter, this does not raise an issue of environmental impacts. SCAQMD staff has discussed this approach with EPA staff, and they did not express concerns or indicate that the provision would not be approvable into the State Implementation Plan (SIP). As for not addressing the needs of new power plants constructed after rule adoption, these emissions are included in the growth factor for the electric power industry. The comment asserts that the negative growth factor used for this industry (i.e., projected decrease in total gas-fired power generation) is not consistent with the California Air Resources Board AB 1318 Assessment Report, which shows a need for significant power plant peaking capacity in the future. However, the two projections are not necessarily inconsistent. As the power industry continues to rely more on renewable sources of power such as solar and wind, peaking capacity is needed for the times when renewables are not available, but total quarterly emissions may still go down due to the increased use of renewable sources that do not emit NOx. RECLAIM compliance is measured on a quarterly basis. However, to address concerns about potential not yet foreseeable increased demand for fossil-fueled power generation, staff proposes a Governing Board resolution that will direct staff to monitor this issue and report to the Governing Board or Stationary Source Committee, and will propose any necessary adjustments to the program as appropriate in the future. Therefore, staff believes that no significant environmental impacts have been omitted from the PEA relative to this issue. See also Response 2-39 for a description of the revised staff proposal that addresses many of the concerns that EGF stakeholders have raised.

2-59 This comment reiterates issues previously raised. See Response 2-54.

2-60 This comment asserts that the PEA did not adequately consider the impacts on facilities who must buy RTCs at a higher price, or the impacts of new facilities not being able to buy RTCs and thus locating outside the South Coast Air Basin. In the Draft Final Socioeconomic Report, staff analyzed potential economic impacts of increased prices for RTCs, at several price points, on the smaller facilities that are not subject to the shave, but did not identify any resulting environmental impacts. In addition to considering all the costs of compliance with the proposed amendments, the socioeconomic impact analysis also considered all the costs of compliance with the CEQA alternatives. The Revised Draft Staff Report also explains that SCAQMD staff further considered economic factors by adding a growth factor, a compliance margin, and an allowance for BARCT uncertainty to the target remaining emission levels. Even after full implementation of the shave, there will still be about 20 percent more RTCs in the market than expected emissions, which is within the range of the margin of unused RTCs in past years, excluding the period of the power crisis of 2000-2001. Based on the foregoing, it would be speculative to assume that any facilities would be "unable to obtain RTCs at any price," as asserted in the comment or that any potential new facility would be forced to locate outside of the South Coast Air Basin. See also Responses 2-2 and 2-8. This comment also asserts that since RECLAIM is a market-based system, it cannot be assumed that all the environmental impacts will necessarily occur at the source categories for which SCAQMD has identified new BARCT and which were assumed in the PEA. For a discussion of this issue, see Response 2-51.

2-61 This comment asks for the basis of the statement that 44 facilities are expected to comply with the proposed shave through the purchase of RTCs which will have no environmental impact. By taking the total number of facilities that would be subject to the proposed shave (65) and subtracting the 20 facilities that are expected to install controls, as well as investors, which together are treated as one "facility," a total of 44 facilities would result. However, since the release of the Draft PEA, the number of facilities that would be subject to the proposed shave has been adjusted to 56. Again, by subtracting the 20 facilities that are expected to install controls, as well as investors, which together are treated as one "facility," a total of 35 facilities would result. It is important to note that the sale and/or purchase of RTCs by investors (treated as one facility) will also have no environmental impact. This number is a conservative estimate, because as set forth in Section 9 of the Draft Final Socioeconomic Report, this group of facilities may already have excess RTCs which they can use toward covering their emissions. Simply surrendering excess unused RTCs would not in itself cause adverse environmental impacts. For those facilities that do have to buy RTCs, they will either buy them from those that have excess RTCs, which has no environmental impact, or they will buy them from facilities that install controls, thus freeing up RTCs. The environmental impacts resulting from installing and operating controls have already been analyzed in the PEA. This comment repeats the issue regarding RECLAIM being a market based program. See Response 2-51.

2-62 Table 1-3 shows 8.77 tpd of potential NOx emission reductions due to BARCT for Alternative 3, not 8.0 tpd. This comment is unclear as it seems to say both that the RTC reductions from the Industry Approach, Alternative 3, would equal the staff analysis for

BARCT reductions of 8.77 tpd, and at the same time that this number should be revised downward. It is unclear whether the comment requests the number to be 8.77 or some smaller number. If staff revises Alternative 3 by applying the Industry Proposal that was presented at the Special Stationary Source Committee on September 23, 2015, Alternative 3 would result in 6.6 tpd reductions in RTCs instead.

2-63 This comment reiterates issues previously raised. See Response 2-50.

2-64 This response states that Alternative 3 would achieve 8.77 tpd NOx reductions so the operational NOx reductions are quantifiable, contrary to the statement in Table 1-4. It is more accurate to state that Alternative 3 would result in 8.77 tpd of RTC reductions (unless the Industry Approach is revised to be 6.6 tpd as discussed in Response 2-62). However, this does not translate to actual NOx emission reductions. As explained in Response 2-35, actual NOx emission reductions could be as little as about 0.5 tpd beyond 2005 BARCT levels. There is no evidence to support the argument that facilities will install a significant amount of controls rather than giving up surplus unused RTCs under the Industry Approach, when RTC prices have been $5,500 or lower per discrete ton over the past decade, while the average cost-effectiveness for controls is about $13,615 per ton. Thus, Table 1-4 in the PEA does not need to be revised as suggested.

2-65 This response disputes the statement in Table 1-4 of the PEA that the amount of ammonia use under Alternative 3 is not quantifiable and requests acknowledgement that ammonia use will be lower than under the proposed project. Table 1-4 acknowledges that there will be less use of ammonia under Alternative 3 than there will be under the proposed project because it is expected that fewer controls will be installed and fewer emission reductions obtained. However, the lower usage is not quantifiable because it depends on the number and type of control equipment installed by facilities under Alternative 3 which cannot be accurately predicted. As explained in Response 2-36, Alternative 3 could result in as little as about 0.50 tpd of NOx emission reductions beyond 2005 BARCT levels, or it could result in somewhat greater emission reductions, but the actual amount is not predictable.

This comment also states that construction impacts are quantifiable, contrary to the statement in Table 1-4, because as listed in Table 1-3, Alternative 3 would require emission controls sufficient to obtain 8.77 tpd of reductions. However, Table 1-3 only lists the maximum obtainable RTC reductions from Alternative 3, and then assumes that all of those reductions would occur from the types of equipment identified in that table. As explained in Responses 2-35 and 2-36, this is not a realistic assumption, as it is highly likely that facilities would surrender some amount of unused RTCs in lieu of installing controls, but the exact amount is not foreseeable. So at the time when Table 1-4 was prepared, SCAQMD staff accurately reflected the expectation that construction impacts would be less than under the proposed project, but by an unquantifiable amount. Table 1-4 also acknowledges that Alternative 3 would have fewer construction impacts than the proposed project. If, as claimed by the comment, Alternative 3 actually resulted in obtaining the same actual emission reductions and installing the same controls as the proposed project, it would have the same environmental impacts. See also Responses 2-

41 and 2-43 for the discussion on the impacts relative to the use of ammonia. See also Responses 2-2, 2-33, 2-37, 2-62 and 2-64 for the various discussions on the impacts relative to Alternative 3.

2-66 This comment reiterates issues previously raised. See Responses 2-36 and 2-64.

2-67 This comment reiterates issues previously raised. See Responses 2-8, 2-30, 2-33, 2-34, 2-50, and 2-57.

2-68 The project description and project objectives are not the same thing; see CEQA Guidelines §15124. Further, project objectives are not required to be included in the NOP/IS. See also Response 2-28.

2-69 This comment claims that the Draft PEA should include a market analysis to support the statement that the market has enough unused RTCs to support a reduction of 4 tpd in 2016. Based on data in the Revised Draft Staff Report, emissions in 2011 (using 2012 for EGFs) were 20.72 tpd, while available RTCs were 26.51 tpd. Removing 4 tpd in 2016 would leave a margin of 1.79 tpd or just under 9 percent. While this percent is less than the 10 percent compliance margin allowed for the remaining emissions target under the staff proposal, it is not expected to adversely impact the market since many facilities already have the excess RTCs necessary to contribute their part of the 2016 shave. This comment also states that if the 4 tpd were just a reduction in unused RTCs then that would not equate to an emissions reduction of 4 tpd. Staff agrees. However, for purposes of accounting to EPA in our emissions inventory in the State Implementation Plan (SIP), SCAQMD staff is required to use the RECLAIM RTC amount for future NOx emissions, so reducing total RTCs in 2016 does help with demonstrating emission reductions for the SCAQMD SIP.

2-70 This comment reiterates issues previously raised. See Response 2-12.

2-71 This comment says the PEA should be revised after staff fully describes the proposed amendments and after EPA approves them. Staff believes this comment refers to the provision for a Regional NSR Holding Account. The Draft PEA will be revised to describe the current version of the proposal for a Regional NSR Holding account. However, obtaining EPA approval of the proposed amendments is not a necessary part of analyzing the environmental impacts of the proposed amendments, and final EPA approval cannot be obtained until after the proposed amendments are adopted by the Governing Board and submitted to EPA for inclusion into the SIP.

2-72 This comment reiterates issues previously raised. See Response 2-61.

2-73 This comment claims that page 3.2-34 should be updated to reflect the court invalidation of portions of EPA's GHG Tailoring Rule. Chapter 4.0, Subchapter 4.2, page 4.2-36 already contains a statement that acknowledges this court action. This acknowledgment will be added to page 3.2-34 of the PEA.

2-74 The PEA is based on reasonable assumptions supported by facts provided by the consultants and the reference materials listed in Chapter 6 of the PEA for similar types of projects. Based on staff experience with how refineries look and the likely appearances of cranes and construction equipment, staff does not believe that such temporary construction equipment would significantly adversely affect the aesthetic experience of neighbors looking at a refinery.

It is important to keep in mind that in order for a facility to install control equipment, the facility operator will need to submit a permit application which will undergo a CEQA analysis to determine if the project complies with the analysis in the PEA and whether the project can rely on the PEA or if an additional CEQA document would be required. In the former case, if a facility operator proposes a project that may create impacts to aesthetics or to any other environmental topic that are different than what was analyzed in the PEA, then an additional CEQA analysis would be required to examine the project level impacts. See also Response 2-16 for an explanation as to why the PEA conducts a program level analysis and not a project level analysis.

2-75 The different number of SCRs needed for the refinery boilers and heaters source category in the Preliminary Draft Staff Report (PDSR) (e.g., 76) compared to the Draft PEA (e.g., 74) has been attributed to counting separate individual SCRs for several heaters that share stacks (i.e., heaters D90 and D89 at Refinery 4, and heaters D913 and D914 at Refinery 6). The final count of refinery boilers and heaters has been verified and revised to reflect that 73 SCRs have been assumed for controlling NOx emissions from this source category, which is less than what was disclosed and analyzed in both the PDSR and the Draft PEA. The Staff Report and Final PEA have been updated to disclose this change. This revised number of SCRs does not undermine the analyses in either the PEA or the Staff Report because a reduced number of SCRs than what was previously analyzed means less environmental impacts. Thus, the analysis in the Draft PEA is conservative because it overestimates the potential adverse impacts by three additional SCRs.

The revised number of SCRs also does not adversely affect the socioeconomic analysis because the SCAQMD's consultant, NEC, estimated very high costs for the refinery boiler/heater SCRs based on an assumption that four layers of SCR catalysts should be used to achieve 2 ppmv NOx. NEC's assumption is not consistent with information in the facility permits for the individual refineries and information provided by SCR manufacturers. Thus, SCAQMD staff did not rely on the results of NEC's analysis which assumed only 48 SCRs. Note that the total shave has been reduced by 0.8 tpd (e.g. from 14.8 to 14 tpd) to cover any uncertainties in the analysis.

2-76 Aqueous ammonia is an EPA-regulated toxic substance that is regulated as under §112(r) as a hazardous air pollutant and is subject to analysis for the prevention of accidental releases, which includes the requirement to comply with 40 CFR Part 68 –Chemical Accident Prevention Provisions. Caustic, if made of sodium hydroxide, is an acutely hazardous substance. The analysis in the PEA is conservative in that it considers all types of construction activities that may occur, including those for building storage tanks to store chemicals to support various types of air pollution control equipment. Some chemicals may be subject to Spill Prevention Control and Countermeasure regulations, while others may be subject to a Risk Management Plan. Each facility's required Risk Management Plan may include mitigation (such as containment systems). Stormwater Pollution Prevention Plans (SWPPP) may also require containment for hazardous substances. The best management practice for storing ammonia and sodium hydroxide is to provide secondary containment that can hold up to 110 percent of the storage tank in the event of a spill or tank rupture. It is expected that the affected facilities will follow these standards.

2-77 This comment asserts that the statement that it was assumed that an operator would not install control equipment if the technology exceeded $50,000 per ton conflicts with project objectives. Staff does not identify an inconsistency. This is the assumption that was used to reject candidate BARCT control equipment and to eliminate the application of controls for some specific pieces of equipment. For a discussion of the meaning and use of the $50,000 number, and the fact it is not inconsistent with command-and-control measures, see Response 2-31. Further, the actual BARCT measures included in the staff proposal average about $13,615 per ton, and no single measure even approaches the $50,000 per ton level. See also Responses 2-27 and 6-5.

2-78 As explained in Chapter 4, Subchapter 4.4 of the PEA (see page 4.4-9), the SCAQMD recognizes that of the facilities that may be affected by the proposed project, some are currently permitted to use anhydrous ammonia for existing equipment but any existing anhydrous ammonia tanks are part of the existing setting. However, because current SCAQMD policy no longer allows the use of anhydrous ammonia, any new construction or modification of existing control equipment that needs ammonia to operate would be required to use 19 percent by volume aqueous ammonia. Thus, no offsite consequence analysis for the use of anhydrous ammonia is necessary.

2-79 The PEA already contains a conservative analysis which assumes that lead time will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential control equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining all types of permits and clearances, and scheduling contractors and workers. The time needed to accomplish all of these tasks, including time needed for the permitting process, would not cause or increase any existing environmental impacts.

2-80 This comment reiterates issues previously raised. See Response 2-12.

2-81 As summarized in Table 1-3 of Chapter 1 of the PEA, the NOx emission reduction potential for each source category is identified and totals 8.77 tons per day of NOx emission reductions from conducting a BARCT analysis for the proposed project. Further, an additional 5.23 tons per day of NOx RTCs need to be shaved to fully implement the required BARCT emission reductions. Staff believes that this additional RTC shave is necessary to avoid the result that facilities would simply surrender excess unused RTCs rather than making any substantial amount of real emission reductions. For a discussion of this issue, see Response 2-35.

As explained in Chapter 4, Subchapter 4.0 of the Draft PEA, the installation and operation of new or modified existing NOx emission control equipment at 20 facilities was identified as the only portion of the entire proposal that is expected to result in physical effects that may affect the environment. For this reason, the analysis in the PEA focuses on the physical effects that may occur as a result of constructing new or modifying existing NOx control equipment and operating the equipment once constructed which correlates to achieving the 8.77 tons per day of NOx emission reductions and the additional 5.23 tons per day of shaved NOx RTCs necessary to implement the BARCT reductions. See also Responses 2-2, 2-8 and 2-31.

2-82 This comment reiterates issues previously raised. See Response 2-69.

2-83 This comment claims that the statement in the PEA on page 4.2-18, that the proposed project will reduce 14 tons of NOx RTCs per day, but the actual reduction in NOx emissions may be less than the reduction in RTCs, is inconsistent with the statement on page 1-1, paragraph 4, that the project would result in "14 tons per day of NOx emission reductions." Staff does not identify an inconsistency. The introductory statement on page 1-1 of the PEA explains in general terms that the BARCT analysis could achieve NOx reductions up to 14 tpd and Table 1-3 goes into more detail by showing how the 14 tpd is distributed by a combination of actual emission reductions and reductions in NOx RTCs. Thus, the discussion on page 4.2-18 is consistent with how the 14 tpd is described in Chapter 1 of the PEA. Further, as explained in Response 2-69, the amendments will result in 14 tpd of NOx reductions creditable to the SIP. See also Response 2-50.

2-84 This comment reiterates issues previously raised. See Response 2-81.

2-85 This comment reiterates issues previously raised. See Responses 2-41 and 2-43.

2-86 This comment reiterates issues previously raised. See Responses 2-41 and 2-43.

2-87 This comment contests the statement in the Draft PEA that the control measures in the 2012 AQMP are expected to bring the region into attainment for all national ambient air quality standards by 2023 is incorrect because a significant part of the control strategy is within the Section 182 (e)(5) "black box" measures that have not been defined. This is an issue of semantics, as the Section 182 (e)(5) measures are still control measures. However, SCAQMD staff recognizes that due to the need for very large NOx emission reductions, at least 50 percent beyond the requirements of existing rules and fleet turnover in 2023, all feasible NOx reductions are needed. Indeed, one of the objectives of the proposed amendments is to help attain the national ambient air quality standards.

2-88 This comment reiterates issues previously raised. See Responses 2-34 and 2-65.

2-89 This comment requests the inclusion of an Industry Approach for calculating BARCT to be analyzed in the PEA as a CEQA alternative. This comment claims that the Industry Approach can achieve the project's objectives while reducing impacts.

As explained in Response 2-2, the Draft PEA specifically considered the Industry Approach (Alternative 3) and identified that this alternative would result in fewer impacts during construction and operation than the proposed project. Any alternative with a shave smaller than 14 tpd but larger than the Industry Approach would have environmental impacts in between those identified for the proposed project and the Industry Approach, as it would be expected to result in a lessened need and use of new control equipment. However, as explained in Response 2-33, the proposed NOx RTC shave under Alternative 3 was shown to be substantially less than the proposed project (e.g., 8.77 tpd compared to 14.0 tpd) and the PEA concluded that the entire 8.77 tpd NOx RTC shave could be addressed with unused RTCs without having any facilities modifying their equipment to achieve actual NOx reductions from installing air pollution control equipment. For this reason, Alternative 3 was concluded to not satisfy project objective #2 "to modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment." The Industry Approach (Alternative 3) would not result in achieving the maximum level of reductions achievable and so does not meet the legal requirements under Health and Safety Code §40406, and thus, does not meet all of the project objectives. CEQA does not require consideration of alternatives that do not meet most of the basic project objectives. See CEQA Guidelines §15126.6.

2-90 This comment claims that the Industry Approach would avoid or reduce costs of the proposed project and that the CEQA document, including the alternatives analysis, should contain an analysis of these cost avoidances and reductions.

While economic or social information may be included in an EIR, it is not a requirement. The costs of implementing the proposed project or any of the alternatives is not an environmental impact. Further, economic or social effects of a project shall not be treated as significant effects on the environment. Instead, the focus of the analysis shall be on the physical changes. [CEQA Guidelines § 15131 (a)]. For this reason, the analysis in the PEA does not address the costs associated with achieving the proposed NOx emission reductions or with implementing the alternatives. Instead, as explained in Response 2-19, a socioeconomic analysis has been conducted and the analysis and findings are presented in a separate document, the Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), initially published on September 9, 2015 and revised on October 6, 2015 and November 4, 2015.

2-91 This comment suggests that the CEQA document include a cost-effectiveness analysis of using a 10-year useful life of equipment.

This comment repeats sentiments previously expressed in Comments 2-19, 2-32 and 2-90. In particular, regarding the reasoning behind what equipment useful life period was assumed for the proposed project, see Response 2-32. Regarding why a cost-effectiveness analysis is not included in the PEA, see Responses 2-19 and 2-90.

Comment Letter #3

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October 6, 2015

BY EMAIL (BRADLEIN@AQMD.GOV) AND U.S. MAIL

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Re: Comment Letter on Draft Program Environmental Assessment for Proposed Amended Regulation XX; Cities of Burbank and Pasadena

Dear Ms. Radlein:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting the following comments on the Draft Environmental Assessment ("Draft PEA") for the proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), for which a Notice of Completion was published on August 13, 2015. 3-1 The Draft PEA purports to contain an analysis of the potential adverse environmental impacts that could be generated from the proposed project. Unfortunately, the Draft PEA does not contain any analysis of the potential adverse environmental impacts of the potential shortage of RECLAIM Trading Credits ("RTCs") for future power plant needs, which is of great concern to the Cities. 3-2

While the NOx shave proposal appears to include provisions that would mitigate some of its worst impacts on the Cities' well-controlled power plants, it still does not provide the needed certainty that adequate RTCs will be available at a reasonable price to cover these plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies. 3-3 We have suggested some improvements to the proposal that would provide the needed certainty and address other issues (see the Cities' comment letter on the proposed rule

Barbara Radlein
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dated August 21, 2015). In the absence of these improvements, the NOx shave proposal may have significant adverse air quality impacts that should be addressed in the Final PEA. 3-3 Con't

Both Cities operate their own power plants containing peaking units, and BWP also operates the Magnolia Power Plant ("MPP"), a baseload unit, on behalf of the Southern California Public Power Authority ("SCPPA"). Participants in MPP include Burbank, Pasadena, and four other municipalities. The Cities operate these power plants to serve their municipal customers. RTCs are required not only to cover anticipated annual emissions, but also to meet resource adequacy needs and prepare for utility-specific operating contingencies, such as grid reliability, increased cycling to support integration of renewables, and potential electrification of the transportation system. Unlike other industrial facilities operating under the RECLAIM program, the Cities' power plants are obligated to operate to serve load. If they are unable to serve load, there may be blackouts with serious adverse economic and other consequences. 3-4

The staff proposal would require a 47% reduction in the NOx RTC allocations for these power plants. The proposed reductions are so severe that insufficient RTCs would remain to cover Pasadena's and MPP's anticipated emissions, not to mention RTCs needed for resource adequacy and utility-specific operating contingencies. Pasadena and MPP may need to purchase additional RTCs to cover the shortfall. If these additional RTCs are prohibitively expensive or unavailable, then the Cities may be forced to curtail the output from these facilities in order to remain in compliance with the RECLAIM program. 3-5

One possible consequence of a curtailment of output from the Cities' facilities is that other facilities may generate replacement power. These facilities may be located either inside or outside of the South Coast Air Basin. Wherever they are located, these other facilities are unlikely to have emission rates as low as the emission rates from the Cities' own facilities. The increased emissions from these other facilities, and their potential adverse impacts, should be assessed in the Final PEA. 3-6

For example, replacement power may be generated by facilities that are located in the South Coast Air Basin that are not included in the RECLAIM program or that are included in the program but are not subject to the NOx shave proposal, such as certain co-generation facilities. The emissions would be generated in locations different from the locations of the Cities' facilities, and there are likely to be more emissions than would be generated by the Cities' own well-controlled units. These emissions and their potential adverse impacts, including their impacts on local receptors, should be assessed. These adverse impacts may trigger environmental justice concerns. 3-7

Replacement power may also be generated by facilities that are not located in the South Coast Air Basin. It is possible, for example, that replacement power may be generated by coal-fired units in other states. The potential adverse impacts of these emissions should be assessed. 3-8

Barbara Radlein
October 6, 2015
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When we made a similar comment on the Notice of Preparation of the Draft PEA, the District staff responded by stating that the Cities could purchase whatever RTCs are needed to operate and pass the cost through to our ratepayers. This response is not adequate if the cost of RTCs is exorbitant or if RTCs are not available. 3-8 Con't

District staff also responded by stating that the NOx shave proposal now includes a provision addressing the need for RTCs to cover the so-called "NSR holding requirement" (See our January 30, 2015, comment letter and District staff responses (see Draft PEA, Appendices, pages G-55 and 56). The Draft PEA also refers to a provision providing additional RTCs in the event of a State of Emergency as declared by the Governor (see Draft PEA at 1-16). In our comment letter on the rule proposal, we point out that these various provisions do not adequately protect the Cities against having to obtain additional RTCs when their prices are exorbitant or they are not available. Only our suggested safeguards would provide that needed protection. Absent those safeguards, an analysis of potential adverse impacts is required. 3-9

We appreciate your consideration of our comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Philip Fine, Deputy Executive Officer (by email)
Jill Whynot, Assistant Deputy Executive Officer (by email)

RESPONSES TO COMMENT LETTER #3
(Charles F. Timms, Jr. on behalf of
the City of Burbank Department of Water and Power – October 6, 2015)

3-1 The introduction of the parties represented by the letter does not require a response.

3-2 This issue was previously raised by this commenter in a comment letter relative to the NOP/IS (see Appendix G of the PEA, Comment Letter #5, Response 5-3).

As previously explained, SCAQMD staff acknowledged the unique situation that electricity generators have with regard to operating at BARCT or BACT and the requirement for RTC holdings for New Source Review (NSR) purposes. The project was subsequently revised to contain a proposal which establishes an adjustment account to satisfy the NSR holding requirements which would be funded by the shaved RTCs from new electricity generating facilities (EGFs). Most EGF emissions are much less than their potential to emit, so this provision will help reduce the amount of RTCs that EGFs will need to hold. Moreover, a new rule proposal includes an option for an EGF to opt-out of the RECLAIM NOx program if certain criteria are met. This option provides each EGF with the ability to remain in RECLAIM or exit and operate under a command-and-control environment, whichever best meets their needs. Even if an EGF remains in RECLAIM, SCAQMD staff's analysis shows that there is an adequate surplus of RTCs after BARCT controls are installed so that the purchase of additional RTCs to meet allocation targets will not be an issue. Even so, the rule proposal contains price triggers for RTCs that will prevent prices of RTCs from becoming unreasonable. As a result, the staff analysis shows that there will not be an additional environmental impact. Nevertheless, the RTC price analysis has been considered in the socioeconomic analysis, and the Socioeconomic Report contains such an analysis. The commenter has not provided any evidence or examples of how having to purchase additional RTCs is linked to causing potential adverse environmental impacts. SCAQMD staff disagrees with the assertion that a potential shortage of RTCs for EGFs will cause potential adverse environmental impacts that need to be analyzed in the PEA, since RTCs may be purchased. In any event, PAR 2001 contains provisions that would allow EGFs to opt out of RECLAIM.

3-3 The commenter states that the staff proposal does not provide the certainty that adequate RTCs will be available at a reasonable price to cover the power plants' anticipated emissions, resource adequacy, and other contingencies. The commenter also refers to suggested rule language in its August 21, 2015 comment letter for the proposed rule. Lastly, the commenter states that the adverse impacts should be analyzed if these suggestions are not incorporated.

The staff proposal has been refined over recent months to address many of the concerns that stakeholders have raised. While the staff proposal will not offer RTCs for sale in the event of a power emergency as the commenter proposes, the staff proposal contains several safeguards that would provide EGFs with additional credits in the event of an emergency. The safeguards include access to non-tradable/non-usable RTCs with a faster

3-month trigger, and a new 12-month trigger with a threshold level of $22,500 per ton. In the event of a State of Emergency declared by the Governor, EGFs would have access to non-tradable/non-usable credits. If these credits are exhausted, EGFs would also have access to the credits in the Regional NSR Holding Account. Furthermore, EGFs now have the option to exit the RECLAIM program if they meet certain requirements. Under this option, an EGF would no longer be concerned with the possibility of an RTC shortage, even though staff believes that there will not be a shortage.

No shortage of RTC credits is anticipated since the percent difference of the emissions from the allocation cap would be comparable to that which exists today. As explained in Response 3-2, the commenter has not provided any evidence or examples of how having to purchase additional RTCs is linked to causing potential adverse environmental impacts. SCAQMD staff disagrees with the assertion that there will be a potential shortage of RTCS that will cause potential adverse environmental impacts that need to be analyzed in the PEA.

3-4 The comment asserts that RTCs are required to cover anticipated emissions, resource adequacy, and other contingencies and that the facilities operated by the Cities are obligated to serve load. Without adequate RTCs to cover emissions, the comment claims that blackouts with adverse consequences may occur.

Staff acknowledges the necessity of RTC availability for EGFs like the ones that the commenter represents. However, as stated earlier, staff has determined that there will not be a shortage if BARCT controls are implemented. Also, as explained in Response 3-3, it is unlikely that the proposed project would result in subjecting electricity customers to blackouts since there are safeguards for maintaining an availability of RTCs for EGF utilization. The option for EGFs to exit RECLAIM and the Governing Board Resolution language that will require that staff monitor trends in electricity generation that could result from increased emissions due to cycling to accommodate more renewable energy generation or electrification of the transportation sector will help reduce any potential problems in the future.

3-5 The comment reiterates the sentiments expressed in Comments 3-3 and 3-4 that RTCs are required to cover anticipated emissions, resource adequacy, and other contingencies and that the facilities operated by the Cities may need to curtail their output if the RTCs in the market are either too expensive or unavailable.

The staff proposal would not allow RTC prices to soar to prohibitively expensive prices. As explained Response 3-3, the current proposal now contains a quicker response RTC price trigger in addition to the 12-month trigger that would make more RTCs available to stabilize the market. In addition, the current proposal contains a provision that would allow an EGF to opt-out of the RECLAIM program (see the proposed amendments to Rule 2001) so that an EGF would no longer have to keep, sell, or purchase credits.

3-6 The comment states that a result of curtailment would be that other facilities located either inside or outside the basin would produce replacement power at a higher emission rate and that these impacts should be assessed in the Final PEA.

It is not the intent of the staff proposal to encourage the curtailment of power for customers. As explained in Response 3-3, the proposed RTC shave would not cause a curtailment of power production because the proposed project contains safeguards that would preclude this type of situation. See also Responses 3-4 and 3-5.

3-7 The comment reiterates that replacement power resulting from curtailment may come from other, less-controlled plants that may have localized potential adverse impacts.

The RECLAIM program is designed with a programmatic cap where facilities can buy and sell emission credits and every facility in the NOx RECLAIM program has the ability to purchase credits at the level it desires within the confines of the market. As explained in Responses 3-3 through 3-6, the proposed shave is not expected to result in power curtailment because of the safeguards contains in the project proposal. Thus, no localized impacts or environmental justice impacts from other EGFs would be expected to occur.

3-8 The comment states that replacement power may also come from power generation outside of the Basin. A similar comment was made during the NOP/IS comment period and staff responded by stating that EGFs could purchase the RTCs that are needed and pass the costs to the ratepayers (see Appendix G of the PEA, Comment Letter #5, Response 5-2). The commenter claims that the staff response is inadequate in a situation where the cost of RTCs is too high and RTCs are not available.

As stated in Response 3-5, the safeguards contained in the staff proposal would prevent a situation where there would be a lack of RTCs because the price triggers would prevent the prices from rising unreasonably. See Responses 3-3 through 3-6 for why staff believes that the proposed shave would not result in the curtailment of power and would not cause facilities located outside the Basin to generate replacement power.

3-9 The comment states that despite staff's previous responses to their comment letter submitted relative to the NOP/IS (see Appendix G of the Draft PEA, Comment Letter #5, Responses to Comment Letter #5) regarding the Regional NSR Holding Account and its ability to supply credits in the event of a State of Emergency as declared by the Governor, the provisions do not adequately protect the Cities against having to obtain RTCs that are too high in price or unavailable. The commenter claims that only the safeguards presented by the Cities would provide the needed protection and that, otherwise, the potential adverse impacts would be required to be analyzed.

Staff disagrees with the claim that only the commenter's safeguards would provide availability of credits at a reasonable price. As stated in Response 3-3, staff has revised the proposal since the release of the Draft PEA to further accommodate the concerns of EGFs by providing several market safeguards, including the option for EGFs to opt-out of the program. See also Responses 3-4 through 3-8.

Comment Letter #4

Los Angeles Department of Water & Power

October 6, 2015

Ms. Barbara Radlein
Program Supervisor, CEQA Special Projects
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Los Angeles Department of Water and Power (LADWP) Comments on the Draft Program Environmental Assessment Report for Proposed Amendments to NOx RECLAIM Regulation XX (Draft EA)

Dear Ms. Radlein:

The LADWP appreciates the opportunity to provide the following comments on the Draft EA. In so doing, LADWP remains committed to working with the South Coast Air Quality Management District (SCAQMD) to develop additional workable and cost-effective policies to reduce NOx emissions from all source categories in order to meet the federal ozone standards in the South Coast Air Basin. 4-1

Appendix G of the Draft EA contains SCAQMD's responses to LADWP's comment letter of January 30, 2015. In its comment letter, LADWP stated that the Notice of Preparation (NOP) did not address the potential impacts on energy supply as a result of a significant shave in RECLAIM trading credits (RTCs) allocations in the power plant sector. In response, SCAQMD states that Proposed Amended Rule 2002 has been revised such that the proposal includes an Adjustment Account specifically for power generating facilities for access to additional RTCs if needed by power plants. Although SCAQMD sets up the framework and mechanism for accessing additional RTCs from the adjustment account, it is unclear whether there would be sufficient RTCs in the Adjustment Account for the Power Producing Facilities given that the proposed 14 ton per day shave would dramatically reduce the number of RTCs in the RECLAIM program. 4-2

SCAQMD proposes in its amendments (Rule 2002(f)(4) and (5)) to have an Adjustment Account comprised of RTCs set aside for power producing facilities' access under 4-3

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certain conditions. The draft preliminary staff report states that the Adjustment Account RTCs "would be derived from the proposed programmatic 14 tons per day in NOX reductions." In previous NOx RECLAIM working group meetings, SCAQMD stated that Adjustment Account RTCs derived from the 14 tons per day NOx reductions would not be submitted to the State Implementation Plan (SIP). However, throughout the Draft EA, it is stated that the proposed shave is 14 tons per day without any qualification or limitation on their use for meeting NOx SIP reduction requirements under the Clean Air Act. As a result, it is unclear whether there would be sufficient RTCs in the Adjustment Account for the power producing facilities to address the following purposes: 4-3 Con't

- New Source Review offset needs
- Ability of power producing facilities such as LADWP to meet native load (obligation to serve its customers)
- Ability of power producing facilities to meet reliability standards implemented through the Energy Policy Act of 2005
- Ability of power producing facilities to support increased electrification of transportation and other sources

SCAQMD also states in the Draft EA that "further analysis of the actual BARCT NOx emission control opportunities for the various equipment/process categories demonstrated that the proposed project could achieve 14 tons per day of NOx emission reductions by 2023."[1] We believe that the SCAQMD analysis so far provided does not demonstrate that the power producing facilities have the ability to achieve their share of the NOx RTC reductions while simultaneously meeting their obligations to meet native load. For example, SCAQMD does not address that fact that all of LADWP's generating units in the Los Angeles basin are already retrofitted with BARCT or the most stringent Best Available Control Technology to minimize NOx emissions to the maximum extent technically feasible. This means that a deep shave of 47 percent from current RTC allocations could result in LADWP having to procure RTCs if they are even available or face the inability to meet native load and/or meet reliability standards. Thus, LADWP urges SCAQMD to provide additional information as to how the Adjustment Account would be funded, confirm through analysis that sufficient RTCs would be available for power producing facilities, and provide well-reasoned responses to stakeholder rule recommendations related to access to the RTCs (*e.g.*, that a Reliability Coordinator be able to declare an energy emergency). 4-4

In addition, LADWP remains concerned that the impacts of electrification of transportation and other sources have so far not been addressed in the rulemaking. 4-5

[1] Draft EA, page 1-1

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October 6, 2015

Although SCAQMD staff has indicated that such impacts would be addressed at some point in the future, it is unclear what regulatory mechanisms would be available to supply RTCs back to the RECLAIM program once they are submitted to EPA and thereby effectively surrendered for SIP purposes. For these reasons, and as explained in detail in our comments on the SCAQMD proposal, LADWP urges the development of a SIP crediting mechanism that can account for and provide credit the net decrease in NOx as a result of electrification measures. 4-5 Con't

In summary, SCAQMD has not explained whether there would be sufficient RTCs available in the Adjustment Account or in the overall RECLAIM market for power producing facilities affected under the RECLAIM program. Without a clear understanding of this crucial issue, SCAQMD's analysis of the energy impacts on power producing facilities associated with the NOx RECLAIM amendments is incomplete. This matter needs to be addressed fully before SCAQMD can finalize its proposed amendments to RECLAIM Regulation XX. 4-6

LADWP appreciates the opportunity to provide comment on the Draft EA. If you have any questions or would like additional information, please contact Ms. Jodean Giese of my staff at (213) 367-0409.

Sincerely,

Jennifer Madden for

Mark J. Sedlacek
Director of Environmental Affairs

JG:dms

c: Philip Fine, Ph.D, SCAQMD
Ms. Jill Whynot, SCAQMD
Mr. Joe Cassmassi, SCAQMD
Ms. Jodean Giese

RESPONSES TO COMMENT LETTER #4
(Los Angeles Department of Water and Power – October 6, 2015)

4-1 The SCAQMD appreciates the commenter's willingness to work together to help the region achieve the federal ozone standards.

4-2 The comment refers to a letter submitted relative to the NOP/IS and SCAQMD staff's response explaining that the establishment of the Regional NSR Holding Account would address the impacts that the shave would have on energy supply (see Appendix G of the PEA, Comment Letter #4, Response 4-10). The commenter is unclear if there would be sufficient RTCs in the Regional Account for electricity generating facilities (EGFs), given the 14 ton per day shave.

Since the release of the Draft PEA, SCAQMD staff has made several adjustments to the rule proposal that adds additional safeguards regarding the availability of credits for EGFs. The safeguards include access to non-tradable/non-usable RTCs with a faster 3-month trigger. The 12-month trigger for access remains, but the threshold dollars per ton level is now $22,500. In the event of a State of Emergency declared by the Governor, EGFs would have access to non-tradable/non-usable credits. If these credits are exhausted, EGFs would also have access to the credits in the Regional NSR Holding Account. Furthermore, EGFs now have the option to exit the RECLAIM program if they meet certain requirements such as meeting BARCT or BACT with their equipment and surrendering its credits. With this option, an EGF would no longer be concerned with the possibility of an RTC shortage, even though staff feels that there will not be such a shortage if BARCT controls are implemented for those applicable facilities that were analyzed.

4-3 The commenter requests clarity on how the credits in the Regional NSR Holding Account would address the SIP commitment as it pertains to the 14 ton per day RTC reduction. The commenter also requests clarity as to whether there will be sufficient RTCs in the Regional NSR Holding Account for EGFs for NSR needs, meeting native load, meeting reliability standards, and increased electrification of the transportation sector.

The RTCs in the Regional NSR Holding Account would not be submitted into the SIP. The RTCs in this account would be comprised of the shaved credits from EGFs that are subject to NSR holding requirements. By including these additional refinements to the proposed amendments, SCAQMD staff believes the latest staff proposal addresses the NSR needs for all EGFs subject to these requirements. As explained in Response 4-2, the staff proposal now contains a mechanism that can make credits available for EGFs to meet reliability requirements if there is an extenuating need. The staff proposal also includes resolution language that would require monitoring of the electrification of the transportation sector and adjustments to be made, if necessary. In addition, the proposed opt-out provisions in PAR 2001 is another option available to EGFs that would address all the concerns that the commenter has listed.

4-4 The comment expresses concern that the staff proposal in the Draft PEA does not demonstrate that EGFs can be shaved while still being able to meet the obligation to provide native load. Additionally, the shave would result in the purchase of additional credits, even though EGFs are already at BARCT or BACT. The commenter would like clarity on how the Regional NSR Holding Account would be funded, assurances that credits will be available for EGFs, and provide a response to stakeholder recommendations that a Reliability Coordinator be able to declare a State of Emergency.

As explained in Responses 4-2 and 4-3, the staff proposal would provide a sufficient amount of credits for all the market participants if BARCT is installed for those facilities analyzed and the proposed opt-out language is a new alternative for EGFs operating at BARCT or BACT to have an off ramp from the RECLAIM program. However, the proposed language in PAR 2001 still would require the Governor to declare a State of Emergency in order to access the non-tradable credits.

4-5 The commenter expresses concern that the PEA does not address the electrification of the transportation sector and how credits could be added back to the market if this scenario is realized. The commenter urges the development of a SIP-crediting mechanism that can account for the decrease in basin-wide NOx emissions as a result of electrification measures.

The potential electrification of transportation and other sectors in the future is being considered as part of ongoing air quality planning activities related to the 2016 AQMP. Since the scope of future electrification is uncertain, the associated potential impacts on energy supply due to electrification is also too uncertain to be considered. However, the proposed project includes a Governing Board resolution to regularly meet with representatives from the power-producing sector to monitor any future electrification.

The 2016 AQMP is currently under development and on a completely separate schedule from the proposed project. As the 2016 AQMP development process moves forward, a separate CEQA analysis of the effects of what is proposed for the 2016 AQMP will be conducted and presented as part of a Program EIR which will provide multiple opportunities for review and comment by the public, stakeholders, and other interested parties.

Further, an electricity demand analysis was recently conducted in the Final Environmental Assessment for Rule 2202 Emission Reduction Quantification Protocol for Electric Vehicle Charging Station Projects[15] to determine if sufficient electricity would be available to handle the future projected electricity demand for electric vehicles (EV). The Final EA concluded that there would be less than significant impacts to electricity demand primarily from direct input and reports provided by utility providers, Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP), as follows:

[15] SCAQMD, Final Environmental Assessment for Rule 2202 Emission Reduction Quantification Protocol for Electric Vehicle Charging Station Projects, SCAQMD No. 150123JI, certified May 1, 2015, pp. 2-20 to 2-25. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/rule2202fea.pdf?sfvrsn=2

> *"According to the representatives, both SCE and LADWP have forecasted potential load impacts from increased EV charging in the future. SCE and LADWP currently do not have the need to build any new electric generation facilities or alter the transmission system due to projected EV charging demands."*

Thus, the commenter's expressed concern about the impacts of electrification of this aspect of transportation in this comment is inconsistent with the statements made as part of the rule development process for the Rule 2202 Protocol.

Finally, as explained in both the Revised Draft Staff Report (see Comment Letter 18, Response 18-8) and in Responses 4-3 and 4-5, the commenter's resolution language has been noted and resolution language has been prepared that directs staff to monitor the power-producing sector for trends in power consumption and associated NOx emissions as electricity demand potentially increases. The crediting of basin-wide NOx emissions as a result of electrification would be handled via a SIP amendment in the future.

4-6 The comment summarizes the previous comments by stating that staff has not explained whether there would be sufficient RTCs available in the Regional NSR Holding Account or in the overall market for EGFs and requests that this issue be addressed.

As explained in Responses 4-2 through 4-5, staff believes that the revised proposal is designed to ensure that there will be sufficient RTCs available in the market and to also provide an option for EGFs to exit the RECLAIM program.

Comment Letter #5

PHILLIPS 66

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10/6/2015

Ms. Barbara Radlein
Program Supervisor, CEQA Special Project
Planning, Rules and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Phillips 66 Comments on Draft PEA for NOx RECLAIM Amendments
PHILLIPS 66 COMPANY - LOS ANGELES REFINERY

Dear Ms. Radlein:

Phillips 66 Company supports and adopts the comments on the South Coast Air Quality Management District's (SCAQMD or District) proposed regulation to reduce emissions of oxides of (NOx) from the Regional Clean Air Incentives Market (RECLAIM) Program that were submitted by the Western States Petroleum Association today. Attached to this letter is a copy of those comments. 5-1

Sincerely,

Marshall Waller
Director, Environmental Services, Los Angeles Refinery

Attachments

E150323

Page 1 of 2

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October 6, 2015

VIA ELECTRONIC & FIRST CLASS MAIL

Barbara Radlein
Program Supervisor, CEQA Special Projects
Planning, Rules, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market

Dear Ms. Radlein:

We respectfully submit, on behalf of the Western States Petroleum Association ("WSPA") and its members, these comments on the draft Program Environmental Assessment ("PEA") for Proposed Amended Regulation XX – Regional Clean Air Incentives Market ("RECLAIM"). WSPA is a non-profit trade association that represents oil and gas exploration, production, refining and marketing companies, some of whom own and operate facilities in the RECLAIM program.

The draft PEA suffers from fundamental problems that undermine the entire environmental analysis. The draft PEA purports to consider a project to implement the Air Quality Management Plan ("AQMP") and to evaluate best available retrofit control technology ("BARCT"), but narrowly focuses on construction activities associated with the replacement NOx emissions control equipment for selected facilities to achieve 14 tons per day ("TPD") in NOx reductions. Further, the construction activities that are evaluated in the draft PEA have not been confirmed by the District's independent expert, resulting in a proposed project that is likely infeasible. The District's improper focus on 14 TPD in NOx reductions is particularly apparent in the alternatives analyses where the majority of the alternatives require 14 TPD or more of NOx reductions – a skewed selection of alternatives which fails to meet the "reasonable range of alternatives" requirement. Aside from these fundamental problems, the draft PEA lacks adequate analysis in several individual resource areas.

Ms. Barbara Radlein
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Attachment 1 to this letter provides more detailed comments on this draft PEA from WSPA's technical consultant, and are hereby incorporated by reference. ("Attachment 1").

WSPA has previously submitted numerous comments on the proposed regulation itself, as well as the notice of preparation and initial study ("NOP/IS") for the draft PEA, but these comments have received insufficient attention from the District in its environmental analyses.[1] The District responds to the NOP/IS Letter by claiming that technical analyses have been considered, when an in-depth evaluation of the industry's technical concerns has not been performed.

WSPA has serious concerns with both the proposed rule amendments and the draft PEA, and believe that the requirements under the California Environmental Quality Act ("CEQA") have not been satisfied. Furthermore, both the proposed amendments and the draft PEA must be revised and recirculated to address the comments raised by WSPA and the numerous other commenters in order to correct errors, disclose all significant impacts, and allow the consideration of feasible mitigation measures or project alternatives to reduce or avoid these impacts.

I. Fundamental Problems With The Draft PEA Undermine The Environmental Analysis

Under CEQA, an EIR is an informational document designed to provide public agencies and the public with detailed information about the impacts that a proposed project is likely to have on the environment, analyze the ways in which the significant effects of a project might be minimized, and identify alternatives to the project.[2] The District's draft PEA, as a substitute EIR under its certified regulatory program, is also subject to the substantive provisions of CEQA.[3]

Fundamental flaws in the draft PEA's project description and objectives, the scope of review, and the selection and analysis of alternatives, pervade the document, ultimately resulting in a misleading document in specific resource areas as well. Many of the errors in the draft PEA are related to problems with the methodology, assumptions,

[1] See, in particular, the letter submitted by WSPA dated August 21, 2015 on the preliminary draft staff report ("PDSR") and Attachments 1 and 2 (hereinafter referred to as "WSPA's August 21 Letter"). See also the January 30, 2015 letter submitted by WSPA as part of the Industry RECLAIM Coalition commenting on the NOP/IS (the "NOP/IS Letter"), and WSPA's May 27, 2015 letter on the April 29, 2015 SCAQMD NOx RECLAIM Working Group Meeting. For convenience, these letters are provided as Attachments 2, 3 and 4 to this letter.

[2] Pub. Resources Code §§21002, 21002.1(a), 21061; 14 Cal. Code Regs. §15362; see also Pub. Resources Code §§21100, 21150.

[3] 14 Cal. Code Regs. §15250; *City of Morgan Hill v. Bay Area Air Quality Management District*, 118 Cal.App.4th 861, 874-875 (2004).

Ms. Barbara Radlein
October 6, 2015
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which WSPA described in detail in its August 21 Letter and which are reiterated here as they also relate to inadequacies under CEQA. WSPA believes that the draft PEA must be revised and recirculated for further public review and comment, all in compliance with CEQA.

A. The Project Description is Flawed, Misleading and Hinders Analysis

"An accurate, stable and finite project description is the *sine qua non* of an informative and legally sufficient EIR."[4] An accurate project description is an essential requirement because an EIR must be "prepared with a sufficient degree of analysis to provide decisionmakers with information which enables them to make a decision which intelligently takes account of environmental consequences."[5] If the project description contains inaccurate or misleading information, the entire analysis may be tainted. "A curtailed, enigmatic or unstable project description draws a red herring across the path of public input."[6]

1. The project description includes amendments to Regulation XX, but the draft PEA evaluates only environmental effects of BARCT construction activities

The proposed project is described as "amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements and to modify the RECLAIM trading credit (RTC) 'shaving' methodology."[7] However, the draft PEA examines only the construction activities that purportedly achieve a reduction of 14 TPD of NOx emissions, and fails to evaluate in any manner the potential environmental effects of effectively eliminating the NOx RTC market.

The RECLAIM program is a cap and trade program, and it is misleading for the District to characterize the proposed severe changes to this program as merely a series of construction projects to achieve BARCT requirements. Depending on how they are implemented, changes to the marketplace can have wide-ranging impacts that are not limited to BARCT construction, but also to the operation of the RECLAIM facilities subject to the District's proposed severe shave. The District's focus on NOx emissions reduction – and the PEA's correspondingly limited analysis – has resulted in foreseeable consequences that are neither considered in the District's rulemaking nor analyzed in its environmental assessment in the form of the draft PEA.

[4] *County of Inyo v. City of Los Angeles*, 71 Cal.App.3d 185, 192 (1977).

[5] *Dry Creek Citizens Coalition v County of Tulare*, 70 Cal.App.4th 20, 26 (1999).

[6] *Inyo,* 71 Cal.App.3d at 197-198.

[7] Draft PEA, p. 1-1.

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While the District certainly has the authority to prepare a CEQA document solely for BARCT requirements, and if that is the District's intention with the draft PEA, then the draft PEA needs to clearly state that intention in the project description. "[I]ncessant shifts among different project descriptions" undermines the CEQA process "as a vehicle for public participation."[8] However, the project description purports to include an RTC "shave," and the CEQA document needs to evaluate it. For this reason alone, the draft PEA must be revised and recirculated for further public review and comment.

2. The draft PEA does not substantiate the fundamental assumptions that form the basis of the BARCT construction activities

As explained above, the draft PEA improperly focuses solely on BARCT construction activities for its analysis, but the viability of those construction activities being adequately represented and analyzed in the draft PEA cannot be substantiated, creating further uncertainty for the project description. "An EIR may not define a purpose for a project and then remove from consideration those matters necessary to the assessment of whether the purpose can be achieved."[9] Given that the District has narrowly defined the purpose of the project as implementing BARCT, it still must be able to substantiate that those BARCT construction activities can actually be performed.

The District erroneously assumes all its proposed BARCT requirements are not only technologically feasible but can be achieved unilaterally despite evidence suggesting the proposed BARCT levels may not be cost effective or feasible for all RECLAIM facilities subject to the District's proposed severe shave. As WSPA has explained previously, most recently in its August 21 Letter, this is not the case. In November 2014, Norton Engineering Consultants ("NEC"), the third party expert hired by the District to "ground truth" the District's technical analysis in this rulemaking, presented findings in its BARCT Feasibility and Analysis Review.[10] However, when the preliminary draft staff report for the proposed amendments was released on July 21, 2015, it was apparent that many of NEC's findings were ignored, misunderstood, or misstated by the District. As described in WSPA's August 21 Letter, failure to correct some of the assumptions and errors in the staff report for this rulemaking skews the analysis for nearly 40 operating units (i.e., RECLAIM NOx sources).

[8] *Inyo,* 71 Cal.App.3d at 197.

[9] *County of Inyo v. City of Los Angeles,* 124 Cal.App.3d 1, 7-9 (1981).

[10] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014, http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-refinery_112614.pdf?sfvrsn=2 (last accessed September 13, 2015).

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Moreover, there is no support for the District's assumption that certain NOx sources subject to this rulemaking can achieve 2 ppm NOx levels using new or upgrade selective catalytic reduction systems ("SCR"). This 2 ppm NOx level assumption is an integral component of the District's calculus justifying the currently proposed severe shave. While CEQA provides that disagreements among experts does not make an EIR inadequate, that is not the case here with the draft PEA.[11] As a threshold matter, the District cannot claim to be an expert in specific applications unique to the refining and petrochemical industry; indeed that is apparently the reason for its hiring of an outside third party expert to verify (i.e., "ground truth") the District's technical assumptions. Importantly, the District has been presented with a highly technical analysis from its own third party expert on the ability – or inability – of certain types of NOx sources to achieve 2 ppm NOx levels using SCR, and effectively dismissed this information in favor of unsubstantiated assertions that certain equipment can, indeed, meet such NOx levels and reductions.[12]

The District also assumes that the installation of the BARCT can and will be implemented in the specified timeframe, which is fairly aggressive. This aggressive time frame is unrealistic and again, has not been substantiated. A number of internal and external factors influence when a company can and will undertake a construction project. WSPA members report that completion of all needed projects to implement the proposed NOx reductions would likely require at least eight (8) years. (Attachment 1, p. 13).[13] It is also a possibility that, depending on the economic climate and incentives, a project would not be implemented at all. In the current economic climate for the oil and gas industry, a more realistic schedule is required for an adequate CEQA review.

The draft PEA also purports to conduct a site-specific analysis for certain resource areas, but makes unsubstantiated conclusions to eliminate further environmental analysis. For example, the PEA determines noise impacts will not occur from the project because any increase in noise levels will be within the thresholds of the industrial facilities. The PEA makes similar extrapolations from a site specific review of the aesthetics, taking a specific example of a facility where a wet gas scrubber ("WGS") had been installed, resulting in a characteristic steam plume. The PEA essentially states that because these refineries are in industrial areas, additional WGS plumes would not have an aesthetic impact.[14] The PEA's assumptions and extrapolations make an informed analysis difficult.

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[11] See, e.g., *Karlson v. City of Camarillo*, 100 Cal.App.3d 789, 805 (1980).

[12] See letter from NEC to the District dated August 10, 2015, and included as Attachment 2 to WSPA's August 21 Letter, attached to this letter as Attachment 2.

[13] WSPA also recommended that the shave implementation schedule be "back-loaded" to accommodate a longer, more realistic project implementation period with at least 2 of the proposed 4 TPD (currently being proposed for 2016) being moved to 2019 or later. WSPA's August 21 Letter, p. 3, attached to this letter as Attachment 2.

[14] Draft PEA, p. 4.1-4.

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The draft PEA should identify realistic assumptions based on facts to properly evaluate potential environmental effects of construction activities, and a one-size fits all approach that dismisses the potential for environmental effects based on the industrial locations of the facilities is not sufficient.

In short, the PEA makes unsubstantiated industry-wide generalizations in determining that technology is feasible, implementation timeframes are reasonable, the site specific impacts will be negligible, and the individual businesses will perform as expected. These generalizations cannot support the PEA's assumptions, particularly in light of the District's own third party expert's efforts to correct the errors in its technical analysis. If an EIR is "so fundamentally and basically inadequate and conclusory in nature" that public comment on the draft is essentially meaningless, or if significant new information is added to an EIR, it must be recirculated for further public review.[15] The PEA should be revised to substantiate its assumptions and reevaluate its conclusions accordingly, and should then be recirculated for further public review and comment.

B. The PEA Purports To Be A Program-Level Document, But Construction Activities Generally Require Project-Level Review

The draft PEA is described as a "program CEQA document" ostensibly because it consists of proposed amendments to Regulation XX.[16] As noted above, however, the draft PEA appears to evaluate BARCT construction activities, and specific construction projects generally require a project-level analysis. This distinction is important because a program-level review can be more abbreviated and the District apparently seeks to utilize that approach, but it has now embarked on a partial project-level review of BARCT construction activities. As noted above, noise is dismissed in the PEA and not evaluated at all, even though noise is an environmental topic commonly reviewed in a project level EIR for a construction project. If the District seeks to transform a rule-making into a construction project, it needs to do so in compliance with CEQA.

Furthermore, the draft PEA, which is a "substitute CEQA document" pursuant to the District's certified regulatory program, states that the "program" CEQA document may be used by other agencies for "future related actions." Section 15253 of the CEQA Guidelines addresses use of a substitute CEQA document by responsible agencies, and the District should clarify how the provisions of that Section have been satisfied.

The draft PEA's insufficient project level analysis for BARCT construction activities reinforces WSPA's main critique of the District's proposed amendments to Regulation XX—the technical analysis to support the proposed amendments is

[15] *Laurel Heights Improvement Ass'n v Regents of Univ. of Cal.*, 6 Cal.4th 1112 (1993); 14 Cal. Code Regs. §15088.5(a).

[16] Draft PEA, p. 1-3.

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inadequate.[17] If these construction activities had been properly evaluated in the CEQA document at a project level, the infeasibility of the proposed BARCT would have become apparent.

C. The PEA Overlooks Impacts From the "Whole Of The Project"

An EIR must consider the whole of an action.[18] "Project" means the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and that is an activity directly undertaken by any public agency.[19] An "indirect physical change" may be one resulting from any economic and social effects of a project, and that change too must be evaluated.[20] The CEQA Guidelines provide: "Where a physical change is caused by economic or social effects of a project, the physical change may be regarded as a significant effect in the same manner as any other physical change resulting from the project."[21] While not all projects evaluated under CEQA have sufficient economic and social effects to warrant further analysis regarding consequential physical effects, this project is unique in that it consists of amendments to a market system – economic consequences are integral to RECLAIM operations.

1. The Draft PEA fails to consider the physical effects resulting from reasonably foreseeable economic and social effects

The draft PEA summarily asserts: "No indirect or indirect physical changes resulting from economic or social effects have been identified as a result of implementing the proposed project."[22] No citation is provided for this conclusion, and no analysis was performed to support this conclusion. As a result and the clear fact that the draft PEA proposes such a severe RTC "shave" that it could potentially eliminate the NOx RTC market, an analysis must be performed to evaluate the potential physical changes that might result from the reasonably foreseeable economic and social effects of the project.

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[17] *See also* WSPA's August 21 Letter.

[18] Because the District has adopted a Certified Regulatory Program under California Public Resources Code §21080.5, an environmental assessment ("EA") may be prepared instead of an EIR or negative declaration. An EA is the equivalent of an EIR under the Certified Regulatory Program.

[19] Cal. Code Regs. § 15378(a)(1).

[20] CEQA Guidelines Section 15131. See, e.g., *Bakersfield Citizens for Local Control v. City of Bakersfield*, 124 Cal.App.4th 1184 (2004) (holding that CEQA requires consideration of social or economic impacts if they may lead to adverse changes in the physical environment such as "urban decay").

[21] 14 Cal. Code Regs. §15064(e).

[22] Draft PEA, p. 1-16.

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More specifically, the draft PEA fails to consider the physical impacts of an analysis in which the economic consequences of the rule result in reasonably foreseeable changes in the regulated sectors. The District is well aware of the statistic it cites in its staff report and PEA: since the start of the RECLAIM program, the number of facilities in the program has shrunk by approximately 30 percent.[23] Where there were once 392 RECLAIM facilities in the South Coast Air Basin, there are now only 276. While the District cites this statistic, it makes no effort to analyze or consider the significance of it, or to examine the physical changes in the environment that resulted in the PEA.

This reduction in RECLAIM facilities means that some productivity within the Basin has been lost, and the draft PEA should evaluate the potential for future loss of productivity from sources within the RECLAIM system, particularly those RECLAIM facilities subject to the District's proposed severe shave. This analysis in the PEA should evaluate the Basin's energy needs and assess whether there would be adequate sources of reliable power if the proposed project were to result in lowered productivity within RECLAIM facilities and the businesses that support and supply these facilities. It should also consider whether lowered production of the affected products could result in adverse environmental impacts within or outside of the Basin. It should consider the environmental impacts of leakage, which is a well-known, and thus, foreseeable consequence of sub-regional cap and trade schemes. CEQA provides that "[a]ny emissions or discharges that would have a significant effect on the environment in this state" are subject to CEQA.[24] Accordingly, the District is obligated to analyze whether potential changes in operations resulting from the imposition of this aggressive RTC shave would result in potential environmental impacts, including increased emissions due to needing to source products from outside the South Coast Air Basin where the RECLAIM program applies.

The District's incomplete and selective approach neglects to consider potential environmental impacts beyond the narrow scope of construction associated with installation of the anticipated BARCT required by the proposed project. In the District's own words, RECLAIM is a market-based program which was "designed to use the power

[23] Draft PEA, p. 2-2.

[24] Cal. Pub. Resources Code § 21080. In certain instances, the mandate of CEQA to ensure a high level of environmental protection extended to considering out of state activities as part of the project due to resulting in-state impacts. (See 58 Ops. Cal. Atty. Gen. 614 (1975), opining that where California cities were joining forces with Utah cities to construct a coal plant in Utah that would provide power to California, and related transmission lines would have to be built from Utah into California, any project-related EIRs had to examine the environmental consequences of the project as a whole. Additionally, because the project area spanned multiple states, local California agencies were required to look at the impacts of the project as a whole.)

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of the marketplace" to reduce air emissions from stationary sources.[25] A proposed shave effectively manipulates that marketplace. It stands to reason that an aggressive, deep manipulation – like the one proposed by the District – will impact RECLAIM facilities differently than one that is less drastic. The District is proposing a massive change in the marketplace designed to change behavior and cause reactions, yet the District assumes that the only reaction will be small scale construction projects involving installation of NOx control equipment to meet shave requirements. The District is proposing a massive change that will cause RECLAIM facilities and the businesses that support and supply these facilities to *react* in ways that are reasonably foreseeable by the District. These reactions, in turn, will have environmental impacts, which should have been analyzed in the PEA.

The RECLAIM program was introduced as an alternative to traditional command and control requirements, and was intended to provide business within the South Coast Air Basin with greater flexibility and financial incentive to reduce air pollution. As set forth in WSPA's August 21 Letter, the District has accomplished the substantial NOx emissions reductions achieved to date by reducing RTCs across the board. With the present project, not only is the District proposing deep cuts to the remaining RTCs, but it is imposing these cuts in a targeted, uneven manner. This is a significant manipulation of the marketplace, with foreseeable consequences that the PEA has neglected to analyze. The likely impacts resulting from the District's chosen methodology occur in various resource areas, as described further in this letter. However, by not recognizing the market-driven business considerations, the PEA has neglected to analyze and disclose the "whole of the project," in violation of CEQA.

CEQA prohibits segmenting a project into separate actions in order to: avoid environmental review of the "whole of the action"[26]; defer environmental analysis; ignore the foreseeable environmental impacts of the end result of a project; or, avoid considering potential cumulative impacts. Thus, a lead agency may not limit environmental disclosure by ignoring other activities that will ultimately result from approval of a particular project. The District's limited focus on technical equipment related to control of NOx emission reductions to achieve the severe RTC shave, to the exclusion of other foreseeable impacts is evidence of the District's failure to consider the entire project and its potential environmental impacts.

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[25] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim (last accessed September 12, 2015).

[26] Cal. Pub. Resources Code § 21065.

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2. The draft socioeconomic report is deficient, and a revised report should be prepared and recirculated concurrently with a revised draft PEA

The draft Socioeconomic Report for the RECLAIM amendments provides little assistance in evaluating this issue as it considers only a limited number of potential economic and social issues, based solely on BARCT construction activities, and does not delve into the potential for physical effects resulting from the severe RTC "shave." WSPA will be submitting comments on the draft Socioeconomic Report, and once those comments have been considered and addressed, the draft PEA should be revised and recirculated for public review and comment to reflect the District's analysis of the potential environmental effects of any physical changes resulting from these economic and social effects.

Furthermore, the Draft Socioeconomic Report was only circulated on September 7, 2015 – weeks after the completion of the PEA. Failure to consider socioeconomic impacts in conjunction with the environmental review hampers the environmental review of the whole of the project. A proper socioeconomic analysis should have been completed in advance of, or at minimum in conjunction with, the draft PEA, and the draft PEA should have analyzed the resulting physical changes based on the socioeconomic effects of the RECLAIM amendments.

For example, the socioeconomic analysis with respect to the BARCT cost effectiveness could well have environmental impacts which were not adequately analyzed in the PEA. Health and Safety Code §39616 requires RECLAIM to achieve emissions reductions "at equivalent or less cost" than otherwise applicable command and control regulations. The project proposes cost effectiveness of $50,000/ton threshold, above which the District assumes, for purposes of CEQA analysis, that a facility would decline to install the given air pollution control technology. However, as discussed in greater detail below, this $50,000 is more than twice the AQMD's cost effectiveness threshold for command-and-control programs. The socioeconomic impacts of adopting new BARCT threshold, and setting such a high cost effectiveness figure, could result in operational changes which have physical impacts on the environment. In order to comply with CEQA, the PEA must analyze the foreseeable impacts of this component of the project.

D. The Project Objectives Are Disconnected From The Project Evaluated In The Draft PEA

An EIR is required to have a "statement of objectives sought by the proposed project."[27] The statement of objectives should include the underlying purpose of the project, and it should be clearly written to guide the selection of alternatives to be

[27] 14 Cal. Code Regs. §15124(b).

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evaluated in the EIR.[28] Here, however, the objectives do not appear to inform the alternatives; instead, they appear to be independent of the proposed project. In fact, the Alternatives section of the draft PEA contains little analysis of whether the project objectives can be satisfied because they have become irrelevant, thereby infecting the Alternative analysis in its entirety (as discussed below).

The draft PEA appears instead to apply an unstated objective – reduce NOx RTCs by 14 TPD or more – which actually creates inconsistencies with the District's own plans and with the Health & Safety Code provisions with which it purports to comply. The District's 2012 Air Quality Management Plan ("AQMP") included NOx reduction control measure CMB-01. This control measure provided that additional reductions of NOx RTCs in the range of 3 to 5 tons per day ("TPD") would occur. The PEA states that one of the project objectives is to "[a]chieve the proposed NOx emission reduction commitments" of CMB-01. Yet the current project's proposal to reduce NOx RTCs by 14 TPD goes far beyond the control measure's initial recommendation of 3 to 5 TPD target.

WSPA and the Industry RECLAIM Coalition commented on this issue in their NOP/IS Letter. The District's response is that the current project "is the result of a much more rigorous and in-depth analysis as compared to the analysis that supported control measure CMB-01."[29] However, it is apparent that the analysis conducted by the District focused primarily on assessing the maximum number of remaining NOx emissions that could be reduced, to the exclusion of other analyses. As described above, the proposed project has the potential to trigger unintended consequences that were not considered in the draft PEA. The new, aggressive reduction in NOx RTCs, combined with the ambitious timeframe and questionable assumptions about facility performance suggest that the District did not undertake the same holistic view of the RECLAIM program and market as it did when it adopted the 2012 AQMP. Again, it appears that in its zeal to reduce NOx emissions by as much as possible, the District has ignored the potential repercussions of such a severe reduction.

Another unstated, but unsubstantiated, objective is the establishment of a $50,000/ton cost effectiveness threshold that justifies its severe shave. However, this is inconsistent with the stated District's objective: to "[c]omply with the requirements in Health and Safety Code …§39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT."[30] Compliance with that provision of the Health and Safety Code requires that the market-based emissions program should result in (1) emissions reductions equivalent to or greater than reductions that would have resulted under command and control, **and** (2) "***at equivalent or less cost***

[28] 14 Cal. Code Regs. §15124(b).

[29] Draft PEA, p. 1-15.

[30] Draft PEA, p. 2-4.

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compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment."[31] The currently proposed emissions reductions may well provide greater reductions of NOx than would occur under traditional command and control regulation. However, this comes at a cost which far exceeds what implementation of BARCT would cost under command and control.

More specifically, the project proposes a $50,000/ton cost effectiveness threshold, above which the District assumes, for purposes of a CEQA analysis, a facility would decline to install a given NOx air pollution control technology to meet the severe shave requirements.[32] However, this $50,000 is more than twice the District's cost effectiveness threshold for command-and-control programs. As WSPA explains in its August 21 Letter, the 2012 AQMP used a cost threshold for NOx control measures of $22,500 per ton.[33] As another point of reference, the District's current Best Available Control Technology ("BACT") guidance document presents a discounted cash flow ("DCF") cost effectiveness threshold of only $19,100 per ton.[34]

The District, in its preliminary draft staff report for the NOx shave rulemaking, has also made misleading cost analysis assumptions which have the effect of making the overall costs for the severe shave look lower than actual. For example, in its staff report, the District proposed a 25-year Useful Life when calculating equipment cost effectiveness. This is misleading because the District rulemaking – which is often technology forcing – occurs on a more frequent basis. For example, the District last amended the NOx RECLAIM rules only 10 years ago. As WSPA explains in its August 21 Letter, assuming a 25-year project life dilutes the capital cost over a longer period of time than what the company is likely to actually realize.

As discussed below, Alternative 3 (the Industry Approach) meets project objectives, with fewer impacts. Thus, the project, as currently proposed, does not meet CEQA's requirements, and the PEA must be revised and recirculated for public review and comment.

[31] Cal. Health & Saf. Code § 39616(c)(1), emphasis added.

[32] Draft PEA, p. 4.2-7.

[33] SCQAMD, 2012 AQMP, December 2012, pp. 4-43.

[34] SCAQMD, BACT Guidelines, Part C: Policy and Procedures for Non-Major Polluting Facilities, 2006.

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E. The Alternatives Analysis Is Flawed

1. The analysis of alternatives is inadequate to allow for informed comparison

The alternatives analysis is critical to the integrity of an EIR.[35] Under CEQA, an EIR must describe a reasonable range of alternatives to the proposed project, or to its location, that would feasibly attain most of the project's basic objectives while reducing or avoiding any of its significant effects, and must evaluate the comparative merits of those alternatives.[36] The alternatives analysis has been described as "the core of an EIR."[37]

An EIR's analysis of alternatives and mitigation measures must focus on those alternatives with the potential to avoid or lessen a project's significant environmental effects.[38] The alternatives discussed in an EIR should be ones that offer substantial environmental advantages over the proposed project.[39]

Here, the PEA evaluates 5 alternatives, and except for the Alternative 4 (No Project) and Alternative 3 (Industry Approach), all other alternatives propose 14 TPD or more of NOx emission reductions. Given that the proposed project has remaining significant environmental effects with the proposed project at 14 TPD, the failure to include any additional alternatives other than Alternative 3 (Industry Approach) at a lesser reduction of NOx emissions does not satisfy CEQA's requirement for a "reasonable range of alternatives." Furthermore, CEQA generally prohibits a selection of "straw man" alternatives which are intended to be knocked down in favor of the proposed project.[40] The majority of the alternatives require 14 TPD or more of NOx reductions, including an alternative for 15.87 TPD, suggesting that the District's selection of alternatives was guided not by the ability to reduce environmental effects, but by an effort to support the proposed project.

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[35] *In re Bay Delta Programmatic Evtl. Impact Report Coordinated Proceedings*, 43 Cal.4th 1143, 1162 (2008) ["The EIR is the heart of CEQA, and the mitigation and alternatives discussion forms the core of the EIR."]

[36] 14 Cal. Code Regs. §15126.6(a).

[37] *Citizens of Goleta Valley v Board of Supervisors,* 52 Cal.3d 553, 564 (1990).

[38] Pub. Resources Code §21002; 14 Cal. Code Regs. §15126.6(a)-(b).

[39] *Citizens of Goleta Valley v. Board of Supervisors, supra*, 52 Cal.3d at 566.

[40] *Sierra Club v. Contra Costa County*, 10 Cal.App.4th 1212, 1217 (1992).

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2. Alternative 3 is the environmentally superior alternative

The PEA's alternatives analysis is flawed because it appears to reject alternatives based solely on the total TPD of emissions reduced, rather than a more comprehensive analysis that evaluates the remaining significant effects associated with the proposed project. The CEQA Guidelines provide that "the discussion of alternatives shall focus on alternatives to the project or its location which are capable of avoiding or substantially lessening any significant effects of the project, even if these alternatives would impede to some degree the attainment of the project objectives,…"[41] Alternative 3 achieves the project objectives and is the environmentally superior alternative. As such, the District should adopt Alternative 3 rather than the proposed project.

Here, the District has chosen, as the proposed project, to employ a methodology that has significantly greater potential environmental impacts than Alternative 3. Specifically, the District proposes that NOx RTC holdings for major refineries be "shaved" by 67 percent; NOx RTC holdings for non-major refineries and other facilities among the top 90 percent of RTC holders be shaved by 47 percent. This aggressive "shaving" method would remove nearly all of the unused NOx RTCs from the RECLAIM market, ostensibly to reduce NOx emissions from RECLAIM facilities. However, the PEA suffers from a narrow view of the RECLAIM universe: by focusing almost exclusively on potential benefits from NOx emissions, the District fails to analyze the environmental impacts that such a drastic NOx RTC reduction is likely to have.

On the other hand, the Industry Approach (Alternative 3) to NOx reduction would take a more measured and holistic approach, resulting in fewer environmental impacts while still achieving a reduction in NOx emissions. More specifically, the Industry Approach proposes to reduce the unused RTCs in an amount equivalent to those reductions that could be directly attributable to an appropriate and valid BARCT.[42] The Industry Approach would result in an across the board reduction of 33 percent of the unused NOx RTCs – a significant reduction of RTCs and advancement of BARCT – without many of the environmental impacts resulting from the District's methodology.

The draft PEA downplays that Scenario 3 (Industry Alternative) will require less operational use of ammonia, by claiming that it is "not quantifiable."[43] However, no evidence is provided to support that conclusion. In the alternatives air quality analysis, the District asserts that if Alternative 3 were implemented, it would be too difficult to

[41] 14 Cal. Code Regs. § 1526.6(a).

[42] The Industry Approach is described in section 5.3.2.4 of the draft PEA, as well as in the January 30, 2015 letter to the District regarding the NOP/IS, submitted by WSPA and the other members of the Industry RECLAIM Coalition.

[43] Draft PEA, Table 1-4.

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predict the number of facilities that would install NOx control equipment.[44] First, the District should have acknowledged the unpredictability of facilities implementing the proposed project, which is more aggressive and could trigger correspondingly more drastic business reactions. Instead, the District assumes there that all facilities will fall in line to install NOx control equipment as it predicts. Second, the likely NOx control equipment installation projects can be quantified.

Furthermore, the alternatives analysis in the PEA fails to explain why the proposed project will only reduce NOx emissions 8.72 TPD when history suggests a 1:1 relationship between RTC reductions and program emissions.[45] If the project objective is to meet BARCT at 8.7 TPD, Alternative 3 meets that objective with fewer environmental impacts, and thus, should be the environmentally preferred alternative.

The lead agency has the flexibility to approve an alternative to the proposed project if that alternative better addresses the agency's environmental concerns.[46] An EIR's failure to analyze an adequate range of alternatives deprives the lead agency of the ability to provide this sort of meaningful review and selection. Recirculation of a new draft PEA will be required by CEQA because the current PEA has not considered alternatives that have not been previously adequately analyzed but must be analyzed as part of a reasonable range of alternatives.

II. Specific Resource Areas Lack Adequate Analysis

A. Energy Reliability Impacts Were Not Considered

The District's proposal will dramatically increase the costs for the facilities it has selected to be regulated and the businesses that support and supply these facilities. The PEA acknowledges that if the BARCT is implemented at these selected facilities, there will be an increase in the amount of energy used both during construction, and more significantly, during operation of the facilities. But the PEA only considered whether there would be sufficient energy when all the facilities installed and implemented the BARCT. Given that 100 facilities have ceased to exist in the District's RECLAIM market since its inception, the District needs to consider not only whether there will be sufficient energy to power the BARCT NOx control equipment, but whether important energy reliability needs of the region and State can be met or whether they will be impacted by the District's proposal.

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[44] Draft PEA, p. 5-15.

[45] See, e.g., Draft PEA, Table 1-4; SCAQMD Annual RECLAIM Audit Report, March 2015.

[46] *Sierra Club v. City of Orange,* 163 Cal.App. 4th 523, 533 (2008).

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There is a complete absence of any analysis of electricity or fuel supply impacts. The potential for outages, interruptions and severe price spikes should be considered and analyzed. Also, the future growth in energy demand should be assessed and the impact of this proposed project on the ability to maintain adequate energy supply. This analysis should consider proposed population growth and growth in use of power-consuming electronics (e.g., hospital diagnostic and treatment tools such as high proton lasers are replacing lower-energy using tools) and growth in electrification and energy use more generally.

B. Air Quality Impacts Were Not Fully Addressed

1. Direct impacts of new and expanded ammonia sources are not addressed

The PEA notes that the proposed project will increase operational use of ammonia, a toxic air contaminant, by 39.5 TPD.[47] The increase is due to the large number of new and expanded ammonia emissions sources associated primarily with the larger number of SCRs that would be required to be installed to meet the severe NOx shave requirements. However, the PEA does not address the impacts from a program which results in increased ammonia emissions. Additionally, as the District's other documents acknowledge,[48] ammonia is a precursor to PM2.5. Accordingly, the PEA should have analyzed the regional impacts from increased secondary formation of PM2.5.

Furthermore, the draft PEA's analysis of ammonia slip depends on physical conditions which are explicitly omitted from the project description (e.g., use of Ammonia Slip Catalysts or ASC) despite recommendations by Norton to use ASC.[49] Without the ASC, the ammonia slip could be as great as 20 ppmv, but the draft PEA underestimates the ammonia slip to be 5 ppmv, ostensibly based on permit conditions for new SCRs. However, existing SCRs are not necessarily subject to those permit conditions, and thus, ammonia slip of up to 20 ppmv should be considered in the health risk assessment for ammonia emissions.[50]

[47] Draft PEA, Table 1-4; p. 4.4-9.

[48] See, e.g., Supplement to 24-hour PM2.5 State Implementation Plan for South Coast Air Basin proposed at February 6, 2015 Governing Board meeting, agenda item no. 22 (link: http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-feb6-022.pdf?sfvrsn=2 last accessed on September 16, 2015).

[49] Norton Engineering Consultants, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs, Document No. 14-045-7, July 21, 2015, p. 3; see also Draft PEA, Table 2-3.

[50] Draft PEA, Tables 4.2-18 and 4.2-21.

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2. Cumulative impacts from air emissions are not adequately considered

An EIR must discuss the cumulative impacts of a project when its incremental effects are "cumulatively considerable."[51] Moreover, in the specific context of a programmatic EIR, one of the key purposes of the EIR is to "ensure consideration of cumulative impacts that might be slighted in a case-by-case analysis."[52] Programmatic EIRs play an instrumental role in allowing the lead agency to consider broad policy alternatives and program-wide mitigation measures at an early time when the agency has greater flexibility to deal with basic problems in program implementation, or cumulative impacts.[53] Accordingly, the CEQA Guidelines require lead agencies to explain how implementing the particular requirements in the plan, regulation or program under review "ensure[s] that the project's incremental contribution to the cumulative effect is not cumulatively considerable."[54]

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts."[55] "Cumulatively considerable" impacts are present when "the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects" and activities.[56] A lead agency's threshold findings of significance with regard to cumulative impacts must "be supported by substantial evidence"; and, where found, cumulatively considerable impacts must be adequately mitigated.[57]

As discussed above, there are indirect air impacts from increased ammonia emissions for SCRs. The District also fails to provide substantial evidence that cumulative impacts from increased ammonia emissions for SCRs (which could number in the dozens at a single refinery) will not result in cumulative health risk impact. The PEA makes the conclusory statements that "[e]ven if multiple SCRs are installed at one refinery facility, the locations of all the stacks would not be situated in the same place within the affected facility's property. As such, even with multiple SCR installations, the acute and chronic hazard indices would not be expected exceed the significance

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[51] Pub. Resources Code § 21083(b)(2); CEQA Guidelines § 15130(a).

[52] 14 Cal. Code Regs. § 15168(b)(2).

[53] 14 Cal. Code Regs. § 15168(b)(4).

[54] 14 Cal. Code Regs. § 15064(h)(3).

[55] 14 Cal. Code Regs. § 15355.

[56] Pub. Resources Code § 21083(b)(2); 14 Cal. Code Regs. § 15065(a)(3).

[57] 14 Cal. Code Regs. § 15064.7 (b).

threshold."[58] However, no evidence is provided to support this assumption, and the draft PEA should base its analysis on a conservative assumption regarding the locations of SCRs, and not dismiss the potential environmental effect by relying on unsupported and result-driven assumptions.

Furthermore, the PEA's conclusions with respect to potential cumulative health impacts are contradicted by recent District statements that recognize a potential need to control SCR ammonia slip. In a presentation on August 26, 2015, the District proposes possible "short-term" implementation for such a control.[59] Although CEQA does not require compliance with rule or programs that have not yet been adopted, the PEA should address, in its air quality analysis, the underlying concerns driving the proposed 2016 AQMP control measure. However, the project appears to value NOx RTC reductions above all other concerns, and accordingly the lopsided analysis does not acknowledge the related potential ammonia issues.

C. Water Supply Impacts Are Not Adequately Mitigated

The EIR "must assume that all phases of the project will eventually be built and will need water, and must analyze, to the extent reasonably possible, the impacts of providing water to the entire proposed project." (*Vineyard Area Citizens for Responsible Growth, Inc. v. City of Rancho Cordova*, 40 Cal.4th 412, 431 (2007).) Also, "the future water supplies identified and analyzed must bear a likelihood of actually proving available; speculative sources and unrealistic allocations ('paper water') are insufficient bases for decision-making under CEQA." (*Id*. at 432.)

The draft PEA acknowledges "significant adverse water demand impacts from hydrotesting" requiring the imposition of mitigation measures.[60] The mitigation measures consist of a requirement to use recycled water "if available" and if not, a declaration from the water purveyor indicating why the recycled water cannot be supplied to the project.[61] The draft PEA summarily states that "the potential increase in potable water use cannot be fully supplied either with all potable water or with a combination of recycled water and potable water, since some potable water may still be required." The draft PEA also states: "[T]here is no absolute guarantee at the time of this writing that future supplies of potable or recycled water will be available to all of the affected facilities."

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[58] Draft PEA, p. 4.2-23.

[59] Draft Potential Control Measures Concepts for 2016 AQMP August 2015, at p. 9 (link: http://www.aqmd.gov/docs/default-source/Agendas/aqmp/advisory7-item5-attachment.pdf?sfvrsn=2, last accessed September 16, 2015).

[60] Draft PEA, p. 4.5-9.

[61] Draft PEA, pp. 4.5-9 – 4.5-10.

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CEQA requires a more in-depth evaluation of the availability and reliability of both potable and recycled water for the project.[62] It is insufficient to conclude that a significant impact for water supply exists without providing a more detailed analysis of the amount of water available, the reliability of such water, all of which has become more important as California is facing one of the most serious droughts in history. While the draft PEA identifies the existence of emergency drought regulations, it does not analyze the effect of these regulations – or of local water restrictions – on the facilities subject to the rule.

A similarly deficient analysis was presented in the draft PEA for the water usage associated with the wet gas scrubbers.[63] In that section, the District states that it cannot confirm or verify the use of recycled water and that "it is not known at this time whether water purveyors would be able to supply potable water for those facilities." CEQA requires an actual analysis of the water availability and reliability, and the inability to verify the use of recycled water means that the use of potable water must be evaluated, including an understanding of whether it is available at all.

Furthermore, the draft PEA fails to evaluate any further mitigation measures, other than a commitment to use recycled water, if available. Such mitigation measures are speculative, and may be found to be legally inadequate if they are so undefined that it is impossible to gauge their effectiveness.[64] Feasible – and therefore defensible – mitigation could include provisions in the rule that allow for alternative technologies and additional NOx RTCs in the foreseeable event that water supply is increasingly restricted, and the cost of water increases accordingly.

D. Noise Impacts Should Have Been Analyzed

The NOP/IS for the project determined that noise was among the environmental areas which would not be significantly adversely affected by the project. The PEA, in explaining why noise is not considered, states that the facilities are generally industrial in nature, and any increase in noise levels due to construction and installation of BARCT NOx control equipment would be within acceptable limits for an industrial facility. However, this is an example of the District's programmatic review failing to take into account site-specific conditions which could have an adverse impact. Rather than make generalizations about the facilities and extrapolated that there will be no adverse noise levels, the PEA should have undertaken a more conservative analysis to assess whether noise could, in fact, adversely affect receptors in the vicinity of the facilities, including on

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[62] *California Oak Foundation v. City of Santa Clarita,* 133 Cal.App.4th 1219, 1237 (2005) (EIR requires "forthright discussion of a significant factor that could affect water supplies).

[63] Draft PEA, p. 4.5-12 – 4.5-13.

[64] *Federation of Hillside & Canyon Ass'ns v. City of Los Angeles*, 83 Cal.App.4th 1252, 1260 (2000); *Preserve Wild Santee v. City of Santee*, 201 Cal.App.4th 260 (2012).

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nearby roadways based on the local noise ordinances or requirements. Noise impacts could occur from the use of large construction equipment to construct and install NOx control equipment and increase in construction traffic, which can include large trucks, trailers and cranes. Additionally, there could be an increase in noise impacts associated with the operation of the NOx control equipment and the ammonia delivery trucks.

E. Solid And Hazardous Waste Is Not Adequately Considered

The PEA fails to adequately analyze potential impacts of hazardous waste as a result of the project. The significant NOx RTC reductions necessitate a high degree of BARCT NOx control installation, most of which consists of SCR technology. While SCR technology has been used in a wide variety of applications and industries over the decades, it nonetheless is generates a hazardous wastestream in the form of spent catalyst which, in turn, requires potential on site storage and off-site transport and disposal.[65] Section 4.6 of the PEA acknowledges that the hazards exist and acknowledges that the generation of hazardous waste and materials will increase. The PEA should also evaluate the impact on communities near hazardous waste landfills, such as Kettlemen Hills, where the impacts may be greater without any corresponding benefit from the District's proposed action. Also, as discussed earlier, the emissions implications of the increased ammonia from the SCR have been overlooked in the District's PEA.

F. Growth-Inducing Impacts Analysis Is Flawed

An EIR must describe any growth-inducing impacts of the proposed project.[66] As part of the analysis, the EIR must discuss ways in which the project could directly or indirectly foster economic or population growth,[67] and should also describe growth-accommodating features of the project that may remove obstacles to population growth. An EIR must discuss growth-inducing effects even though those effects will result only indirectly from the project.[68] A discussion on growth-inducing effects should not necessarily make assumptions about whether the growth is beneficial, detrimental, or inconsequential to the environment.[69] The purpose of the EIR is to act as an informational document.

Here, not only does the draft PEA fail to consider the significance of the shrinking number of RECLAIM facilities (as discussed in Section I.C. of this letter), but the PEA also fails to consider the possibility that the facilities within the RECLAIM universe

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[65] See, e.g., "Alternative Control Techniques Document – NOx Emissions from Process Heaters, (U.S. EPA, September 1993), http://www3.epa.gov/ttn/catc/dir1/procheat.pdf.

[66] Pub. Resources Code §21100(b)(5); 14 Cal. Code Regs. §15126(d).

[67] 14 Cal. Code Regs. §15126.2(d).

[68] *Napa Citizens for Honest Gov't v Napa County Bd. of Supervisors*, 91 Cal.App.4th 342, 368 (2001).

[69] 14 Cal. Code Regs. §15126.2(d).

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could grow. In a footnote, the PEA assigns a "growth factor" to different categories of RECLAIM facilities.[70] No explanation is provided about how that growth factor was derived, nor whether it is current or likely to change. The PEA must consider a scenario which allows for more growth of those industries within the RECLAIM universe, and modify the growth-inducing impacts analysis accordingly.[71]

III. Conclusion

The District has a very admirable – but narrow – statutorily defined focus: to promulgate rules and regulations which promote air quality in its jurisdiction. Under CEQA, the District is the lead agency for purposes of its own rulemaking. The District must be able to square its obligations as a lead agency to fully analyze and disclose impacts of its discretionary approvals with the narrow focus required of the District's mission to promote air quality within a specific geographic area. The District has failed to adequately balance those obligations here, which has resulted in a PEA that presents a skewed analysis of the potential benefits and impacts of the proposed rule amendments. The District must address the numerous inadequacies of the draft PEA raised in this comment letter, and then, revise and recirculate the draft PEA for public review and comment in order to meet its mandate under CEQA.

Sincerely,

Nicki Carlsen
ALSTON & BIRD LLP

NC:dtc
LEGAL02/35874006v4

cc: Sue Gornick,WSPA (w/enclosures)

[70] Draft PEA, p. 2-6.

[71] The Growth Inducement section is in Section 4.8.3 of the draft PEA.

ATTACHMENT 1

ADDITIONAL WSPA COMMENTS ON DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT (PEA) FOR NO_X RECLAIM AMENDMENTS

Page/Section	WSPA Comment
Page 1-1, 3rd paragraph	This paragraph describes the project as "amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements and to modify the RECLAIM trading credit (RTC) "shaving" methodology." [emphasis added] This description is not consistent with the project description contained in the AQMD's Notice of Preparation issued 4 December 2014,[1] nor is the description consistent with Project Description contained in the Initial Study.[2] Specifically, neither the NOP Project Description nor the Initial Study Project Description includes any reference to modifying "the RECLAIM trading credit (RTC) "shaving" methodology" in the description of the project or the project objectives.
Page 1-1, 4th paragraph	The Draft PEA states that "further analysis of the actual BARCT NOx emission control opportunities for the various equipment/process categories demonstrated that the proposed project could achieve 14 tons per day of NOx emission reductions by 2023 which is much higher than estimates provided in the 2012 AQMP." While this value is certainly much higher than contemplated in the 2012 AQMP, it is also not supported by the AQMD Staff's technical analysis.[3] The Staff's analysis does not support a 14 ton per day (TPD) shave as necessary for BARCT equivalency. Rather, the Preliminary Draft Staff Report (PDSR) very clearly demonstrates that not more than 8.79 TPD of emission reductions from the RECLAIM program can be attributed to BARCT advancement; a conclusion that is later echoed in the Draft PEA.[4] Furthermore, a 14 TPD shave reduction of the RECLAIM market may violate the project objectives under the California Health & Safety Code (H&SC). Contrary to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is absolutely no consideration of the economic impacts which would be incurred by RECLAIM facilities under a 14 TPD market adjustment that goes beyond BARCT.

[1] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."
[2] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.
[3] AQMD, Preliminary Draft Staff Report (PDSR) for Proposed Amendments to NOx RECLAIM, 21 July 2015.
[4] AQMD, Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Table 1-3.

	And contrary to H&SC §39616(c)(1), AQMD Staff has failed to demonstrate that the RECLAIM program will result in an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment**. Staff has instead applied a cost effectiveness threshold for this RECLAIM rulemaking of $50,000 per ton of NOx reduction which is more than double the cost threshold used for command-and-control rules within the District (i.e., $22,500 per ton[5]). This higher cost threshold clearly imposes a greater cost on RECLAIM sources than would be incurred under command and control regulations. But the Staff proposal to shave 14 TPD, which goes beyond BARCT, exposes RECLAIM facilities to even greater costs than would have been incurred under a command-and-control program. According the Staff's analysis, BARCT equivalency is not more than 8.79 TPD and even that value is overstated since adjustments are needed to account for the findings of the AQMD's third-party refinery expert (Norton Engineering) would reduce the shave for BARCT equivalency to not more than 7.94 TPD.[6] And contrary to H&SC §39616(c)(7), AQMD has failed to demonstrate that the RECLAIM program as amended will not result in disproportionate impacts, measured on an aggregate basis, to those stationary sources included in the program as compared to other permitted stationary sources in the district's plan for attainment. RECLAIM program sources have already reduced NOx emissions by 69% since 1994, whereas command-and-control stationary sources have only reduced NOx emissions by about 44% during that same period.[7] The BARCT levels being proposed by AQMD Staff represent performance levels that have not been demonstrated as broadly achievable for most of the source categories in question. Furthermore, these performance levels go well beyond the command-and-control standards adopted by AQMD under Regulation XI (i.e., the District's command-and-control program), and are well beyond BARCT determinations made by other major California air agencies administering command-and-control programs (e.g., SJVAPCD, BAAQMD, etc.). The resultant impacts would be disproportionate and that is in conflict with H&SC §39616(c)(7). For these reasons, the Draft PEA must be revised to address inconsistencies between the AQMD Staff's proposal and the project objectives, as well as inconsistencies with the Health & Safety Code.
Page 1-2, 1st full paragraph	This paragraph suggests that the proposed project will be limited to specific types of equipment/source categories in the RECLAIM program. While these types of equipment/source categories are certainly in the

5 AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
6 AQMD, Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.
7 "RECLAIM Sources" data is computed from data presented in AQMD's RECLAIM Audit Report (March 2015). Command-and-control stationary sources NOx emissions is computed from data presented in AQMD Air Quality Management Plans (1997, 2003, 2007, 2012) and AQMP NOx RECLAIM Working Group Meeting #5, Agenda Item #3.

	RECLAIM program, the program is a market-based program; not a command-and-control program. Furthermore, the stated objectives of Control Measure CMB-01 Phase I and Phase II which this rulemaking intends to implement are for **programmatic equivalency.** Since this is a market-based system, it cannot be assumed that all impacts from the proposed rulemaking will be exclusively borne by specific equipment/source categories even where AQMD Staff have clearly attempted to target those impacts on specific facilities as is clearly the case here. The language in the referenced section needs to be revised to reflect that (a) proposed project is seeking programmatic equivalency within the requirements and limitations of the California Health & Safety Code and (b) acknowledge that there may be impacts on other RECLAIM facilities given the market-based design of the RECLAIM program. Those impacts must be analyzed to the extent practicable.
Page 1-2, 2nd full paragraph	As discussed above (see comments on Page 1-1, 4th paragraph), the Draft PEA must be revised to address inconsistencies between the AQMD Staff's proposal and the project objectives.
Page 1-13, Table 1-1, Areas of Controversy Line 1, Amount of proposed NOx shave and availability of RTCs	Draft PEA claims "The staff analysis shows that after the proposed shave is imposed, there will be sufficient NOx RTCs available to maintain trading within the NOx RECLAIM program given foreseeable opportunities for emissions reductions." This statement is without technical foundation; neither the PEA nor the PDSR includes such a market analysis. On the contrary, the Staff's proposal would reduce the quantity of RECLAIM Trading Credit (RTCs) to levels without historical precedent and that action, according to Staff's own analysis, would result in a level of "unused" RTCs (i.e., RTCs not used to cover facility emissions) for which the only historical precedent was observed during the RECLAIM market collapse during the California power crisis of 2000-2001.[8] WSPA and the Industry RECLAIM Coalition have repeatedly expressed concerns about shaving the RECLAIM program to this level when such action is clearly beyond what is needed for BARCT equivalency and in conflict with California Health & Safety Code requirements. Table 1-1 must be revised to accurately reflect the actual technical record; not assert conclusions without technical foundation.
Page 1-14, Table 1-1, Areas of Controversy Line 2, Equity of proposed NOx shave	The Draft PEA states that for 210 facilities holding 10% of the available NOx RTCs that "no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified…for the types of equipment and source categories." This statement is factually incorrect and should be corrected. In actuality, AQMD Staff elected not to review BARCT for these facilities under this RECLAIM rulemaking. And contrary to the statement, AQMD and other California air districts have previously made BARCT determinations that do apply to the types of equipment and operations at those smaller emitting facilities (e.g., boilers, heaters, etc.) were they not under RECLAIM.[9]

[8] AQMD Annual RECLAIM Audit Report, March 2015.
[9] See SCAQMD Regulation XI for examples.

Page 1-14, Table 1-1, Areas of Controversy Line 3, Results of the BARCT analysis	The Draft PEA states "While staff believes the engineering assumptions in the staff BARCT analysis are appropriate, the difference in BARCT reductions attributable to the alternate engineering assumptions suggested by the consultant is relatively small. To account for this difference and to provide a compliance margin, staff is proposing a shave of 14 tpd, reduced from the initial BARCT result of 14.85 tpd." We disagree. There continues to be a significant number of unresolved issues which result in uncertainty in the Staff's BARCT analysis as presented in the PDSR. This includes, but is not limited to the Staff's decision to selectively ignore the findings of the agreed upon third-party expert for the Refinery Sector, Norton Engineering Consultants. These issues are fundamental to the engineering design basis of the Staff's proposed BARCT determinations for most refinery sector source categories. These discrepancies were exhaustively described in Norton Engineering's expert analysis of the AQMD Staff's analysis,[10] as well as reiterated in NEC's letters dated 10 August 2015[11] and 4 September 2015.[12] Norton's comments are incorporated herein by reference. Furthermore, Staff's "after-the-fact" 0.85 TPD adjustment to the overall shave (i.e., reduces proposed shave from 14.85 to 14.0 TPD) is an improper application of the adjustments necessitated by Norton Engineering's expert findings. Such an adjustment, which is necessary, must be applied to the quantity of BARCT equivalency emission reductions attributed to refinery sector source categories. By failing to properly adjust this value, the AQMD Staff have distorted their own methodology to increase the burden of this shave on one sector (i.e., refineries). This is disproportionate and without technical foundation.

[10] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

[11] James Norton, NEC, letter to Dr. Phillip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

[12] James Norton, NEC, letter to Dr. Phillip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for Fired Heaters & Boilers Document No. 14-045-8, 4 September 2015.

Page 1-14, Table 1-1, Areas of Controversy Line 4, Equivalency with command-and-control	The Draft PEA asserts that the proposed shave amount of 14 tpd is consistent with previous RECLAIM rule amendments, the California Health & Safety Code, and the purpose of the program. As noted above (see above comments on Page 1-1, 4th paragraph), the AQMD Staff have not demonstrated that the Staff proposal is consistent with certain provisions of the California Health & Safety Code. Table 1-1, Line 4 must be revised to describe how the Staff proposal will comply with the project objective requiring compliance with all applicable H&SC requirements. The Draft PEA goes on to state "…This approach will result in approximately 8.79 tons per day of BARCT reductions of actual NOx emissions attributable to installing and operating additional controls. Otherwise, actual emissions reductions of only about two tpd over the next seven years would be achieved." WSPA agrees that under the AQMD Staff's analysis, BARCT equivalency as currently presented is not more than 8.79 TPD. And with adjustments needed to fully account for the findings of the AQMD's third-party refinery expert, Norton Engineering, the shave needed for BARCT equivalency is not more than 7.94 TPD.[13] Staff has provided no information to support the assertion that 14 TPD must be shaved to achieve the 8.79 TPD (or 7.94 TPD) required for BARCT equivalency. And RECLAIM program history does not support that conclusion. Under the 2005 Shave, a 23% reduction in RTCs resulted in a 24% reduction in NOx RECLAIM emissions; a nearly 1:1 relationship.[14] The Staff proposal must be revised to reflect the project objective of BARCT equivalency. That has not been demonstrated as any more than 8.79 TPD.
Page 1-15, Table 1-1, Areas of Controversy Line 5, 2012 AQMP Commitment in the State Implementation Plan (SIP)	The Draft PEA states: "This staff proposal recommends a reasonably available 14 tpd of NOx RTC reductions, based on BARCT, as required by state law." In fact, the PDSR presents BARCT equivalency as not more than 8.79 TPD, and the AQMD Staff have not explained how its proposal will comply with H&SC §40406, since there is no consideration of the economic impacts which would be incurred under a 14 TPD market adjustment that goes beyond BARCT. Furthermore, AQMD Staff's proposal is contrary to H&SC §39616(c)(1), which requires the market to perform at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment. The Draft PEA must be revised to fully demonstrated compliance with the project objectives and relevant H&SC requirements.

[13] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.
[14] SCAQMD Annual RECLAIM Audit Report, March 2015. Under the 2005 shave, RTCs were reduced from 34.2 to 26.5 TPD between 2005 and 2011 and emissions declined from 26.4 to 20 TPD over the same period.

Page 1-16, Table 1-1, Areas of Controversy Line 6, Availability of RTCs for future power plant needs	The Draft PEA states" The staff proposal would establish a separate adjustment account to hold RTCs for power plants to meet their NSR holding obligations. Many newer peaking plants are required to hold RTCs at the potential to emit level each year even though their actual emissions are far below this level. The adjustment account would relieve power producing facilities from the obligation of holding RTCs in order to meet the NSR holding requirements of Rule 2005." The AQMD Staff proposal for a separate "adjustment account" has not been fully defined, and the Staff proposal and Draft PEA fail to address how such a mechanism would comply with U.S. EPA requirements for New Source Review. The PDSR and Draft PEA must be revised to demonstrate how such a proposed adjustment account would function, and demonstrate that it is approvable by U.S. EPA. Furthermore, Staff's proposal would apparently not apply to new peaking power plants. The California Air Resources Board prepared assessment of electrical grid reliability needs in the South Coast air basin which suggested a significant amount of peaking power plant capacity would be needed to ensure reliability in the future.[15] This report was prepared in conjunction with the California's power sector regulators (i.e., California Public Utilities Commission, California Independent System Operator, and California Energy Commission). Contrary to the CARB report, AQMD Staff's analysis depends on a negative growth rate for power sector emissions and RTC demand. This is a significant difference. The Draft PEA should be revised to clarify that the Staff proposal would provide no relief to any new peaking power plants. The Draft PEA should also be revised to demonstrate how the Staff proposal will accommodate new power sector facilities which may be needed to ensure electric reliability and integration of renewable electricity.
Page 1-17, 3rd paragraph	The Draft PEA states "For the remaining 210 facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT (not cost effective and/or infeasible) was identified for the types of equipment and source categories at these facilities." This statement is factually incorrect and should be revised. As noted above, AQMD Staff elected not to review BARCT for these smaller facilities for this RECLAIM rulemaking (i.e., no analysis was performed).

[15] CARB, Assembly Bill 1318: Assessment of Electrical Grid Reliability Needs and Offset Requirements in the South Coast Air Basin, Draft Final Report, October 2013.

Page 1-20, 1st paragraph, 3rd sentence Air Quality and Greenhouse Gases	The Draft PEA states "For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will affect 65 facilities plus the investors, who collectively hold 90 percent of the NOx RTC holdings." This paragraph suggests that the proposed project will be limited to specific facilities in the RECLAIM program. While the application of the shave may be limited to these facilities, the impacts of the proposed shave will be broader. RECLAIM is a market-based program; not a command-and-control program. Since this is a market-based system, it cannot be assumed that all impacts from the proposed rulemaking will be exclusively borne by specific equipment/source categories even where AQMD Staff have clearly attempted to target those impacts on specific facilities as is clearly the case here. For example, smaller facilities without Infinite Year Basis (IYB) RTC holdings may incur higher RTC prices to meet their future compliance obligations. Alternatively, such facilities may find themselves unable to purchase RTCs at any price similar to the RTC supply crisis observed during the 2000/2001 power crisis which nearly collapsed the RECLAIM program. Also, Staff has not considered potential impacts to new or expanding facilities which are required to participate in RECLAIM. Or the potential consequences to the regional economy if those facilities are unable to obtain RTC supply. Or the potential environmental impacts of those operations if they are forced to locate outside of the South Coast air basin where they would presumably be subjected to lessor regulation. These are all issues and impacts which have been identified and should be disclosed as potential impacts from the project. The Draft PEA must be revised to clarify that market impacts may be broader than intended or even recognized by Staff, and those impacts must be quantified to the extent possible.
Page 1-20, 2nd paragraph	The Draft PEA states "…only 44 facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact." The Draft PEA should be revised to present supporting analysis demonstrating how this conclusion was reached. RECLAIM is a market-based program; not a command-and-control program. Since this is a market-based system, it cannot be assumed that all impacts from the proposed rulemaking will be exclusively borne by specific equipment/source categories even where AQMD Staff have clearly attempted to target those impacts on specific facilities as is clearly the case here.
Table 1-3, Summary of Proposed Project & Alternatives Alternative 3	This table reports the NOx Reduction Potential (tons/day) for Alternative 3 at 8.00 TPD. As proposed by the Industry, RECLAIM Coalition, Alternative 3 would result in BARCT equivalent reductions. Using the AQMD Staff's latest BARCT analysis, which needs to be revised downward as discussed earlier herein, the Proposed NOx RTC "Shave" for this alternative should be 8.79 TPD. The Draft PEA should be revised.

Table 1-3, Summary of Proposed Project & Alternatives Proposed Project Page 1-26	This table clearly shows that the AQMD Staff proposal, which would shave 14 TPD, would include removing 5.21 TPD of RTCs from the RECLAIM market that cannot be attributed to BARCT. The table even labels these 5.21 TPD as "NOx RTCs Needed to Fulfill Shave Post-BARCT." [Emphasis Added] This proposal is beyond BARCT. Furthermore, a 14 TPD shave reduction of the RECLAIM market could violate the project objectives under the California Health & Safety Code (H&SC). Contrary to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is absolutely no consideration of the economic impacts which would be incurred under a 14 TPD market adjustment that goes Beyond BARCT. Contrary to H&SC §39616(c)(1), AQMD Staff has failed to demonstrate that the RECLAIM program will result in an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment**. Staff has instead applied a cost effectiveness threshold for this RECLAIM rulemaking of $50,000 per ton of NOx reduction which is more than double the cost threshold used for command-and-control rules within the District (i.e., $22,500 per ton[16]). This clearly imposing a greater cost on RECLAIM sources than would be incurred under command and control regulations. Furthermore, Staff has proposed a market shave of 14 TPD which goes beyond BARCT. Under AQMD Staff's analysis, BARCT equivalency is currently presented as not more than 8.79 TPD. Even that value is overstated since adjustments needed to fully account for the findings of the AQMD's third-party refinery expert, Norton Engineering, would reduce the shave for BARCT equivalency to not more than 7.94 TPD.[17] Thus, RECLAIM facilities would have greater costs under the Staff proposal than would have been incurred under a command-and-control program. And contrary to H&SC §39616(c)(7), AQMD has failed to demonstrate that the RECLAIM program as amended will not result in disproportionate impacts, measured on an aggregate basis, to those stationary sources included in the program as compared to other permitted stationary sources in the District's plan for attainment. RECLAIM program sources have already reduced NOx emissions by 69% since 1994, whereas command-and-control stationary sources have only reduced NOx emissions by about 44% during that same period.[18] The BARCT levels being proposed by

[16] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
[17] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.
[18] "RECLAIM Sources" data is computed from data presented in AQMD's RECLAIM Audit Report (March 2015). Command-and-control stationary sources NOx emissions is computed from data presented in AQMD Air Quality

	AQMD Staff generally represent performance levels that have not been demonstrated as broadly achievable for the source categories in question. Furthermore, these performance levels go well beyond the command-and-control standards adopted by AQMD under Regulation XI (i.e., the District's command-and-control program), and are well beyond BARCT determinations made by other major California air agencies administering command-and-control programs (e.g., SJVAPCD, BAAQMD, etc.). For these reasons, the Draft PEA must be revised to address inconsistencies between the AQMD Staff's proposal and the project objectives.
Table 1-4, Comparison of Adverse Environmental Impacts of the Alternatives Row 3: Air Quality & GHGs	This table reports for Alternative 3 "Less operational NOx reductions than proposed project but not quantifiable." As correctly reported in Table 1-3, Alternative 3 would actually reduce emissions by 8.79 TPD so it clearly is quantifiable. Table 1-4 must be revised to correctly report the emission reduction potential for Alternative 3.
Table 1-4, Comparison of Adverse Environmental Impacts of the Alternatives Row 3: Air Quality & GHGs Page 1-29	For the proposed project, the table reports "Increases operational use of NH3 (a TAC) by 39.5 tpd." But for Alternative 3, the table reports that ammonia (NH3) use is not quantifiable. However, no evidence is provided to support that conclusion. In the alternatives air quality analysis, the District asserts that if Alternative 3 were implemented, it would be too difficult to predict the number of facilities that would install NOx control equipment. First, the District should have acknowledged the unpredictability of facilities implementing the proposed project, which is more aggressive and could trigger correspondingly more drastic business reactions. Instead, the District assumes there that all facilities will fall in line to install equipment as it predicts (i.e., command and control). Second, the likely NOx control installation projects can be quantified at a program level since it is a function of the same stoichiometric relationship used in the Staff's analysis for the proposed project. The Draft PEA should be revised to provide an estimate of the operational ammonia use for Alternative 3. Since this value will be lower than the proposed project, Alternative 3 would have lower ammonia emissions by comparison and would therefore be environmentally preferable on this issue. Is Staff's estimate for increased operational use of ammonia based on 8.79 TPD of NOx emission reductions (i.e., BARCT equivalency)? Since the Staff's 14 TPD proposal would require significantly greater emission reductions (i.e., beyond BARCT), the Draft PEA should be revised to explain the basis for this ammonia use figure to ensure that project's potential environmental impacts are fully disclosed. The ammonia figure also drives traffic and construction impacts which may be greater than disclosed in the Draft PEA. For similar reasons, the Staff's statement that Alternative 3 emissions for construction are "not quantifiable" is not accurate. As reported in Table 1-3, Alternative 3 would require emission controls sufficient to reduce NOx emissions by 8.79 TPD (again, using the Staff's BARCT analysis). The

Management Plans (1997, 2003, 2007, 2012) and AQMP NOx RECLAIM Working Group Meeting #5, Agenda Item #3.

	Draft PEA must be revised to include a quantified estimate of the construction emissions needed to deliver those emissions control using a methodology similar to the Staff's analysis of the proposed project.
Table 1-4, Comparison of Adverse Environmental Impacts of the Alternatives Row 3: Air Quality & GHGs Page 1-30	The Alternative 3, the Draft PEA reports impacts are "Less than significant; achieves net NOx emission reductions during operation (less reductions than the proposed project <u>but not quantifiable</u>)." [emphasis added] This is not correct. As reported in Table 1-3, Alternative 3 would require emission controls sufficient to reduce NOx emissions by 8.79 TPD (again, using the Staff's BARCT analysis) so clearly the impacts from Alternative 3 are quantifiable. The Draft PEA must be revised to include a quantified estimate of the NOx emission reductions during operation for Alternative 3.
Page 2-2, Section 2.2 Project Objectives	The Draft PEA states: "The objectives of the proposed project are to: 1) Comply with the requirements in Health and Safety Code (HSC) §§40440 and 39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT; 2) Modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment; 3) Ensure that RECLAIM facilities, in aggregate, achieve the same emission reductions that would have occurred under a command-and-control approach; 4) Achieve the proposed NOx emission reduction commitments in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM; and, 5) Achieve NOx emission reductions to assist in attaining the NAAQS." This highlights several problems with the Draft PEA and the Staff proposal. WSPA agrees that AQMD has a legal obligation to comply with the requirements in Health and Safety Code (HSC) §§40440 and 39616. However, Staff has oversimplified what those obligations are by suggesting this is entirely about conducting a BARCT assessment. The AQMD Staff's proposed 14 TPD shave reduction from the RECLAIM market could violate the project objectives under the California Health & Safety Code (H&SC). With respect to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is no consideration of the economic impacts which would be incurred under a larger 14 TPD market adjustment that goes beyond BARCT. With respect to H&SC §39616(c)(1), AQMD Staff has failed to demonstrate that the RECLAIM program will result in an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the**

	District's plan for attainment. Staff has instead applied a cost effectiveness threshold for this RECLAIM rulemaking of $50,000 per ton of NOx reduction which is more than double the cost threshold used for command-and-control rules within the District (i.e., $22,500 per ton[19]). This clearly imposes a greater cost on RECLAIM sources than would be incurred under command and control regulations. Furthermore, Staff has proposed a market shave of 14 TPD which goes beyond BARCT. Under AQMD Staff's analysis, BARCT equivalency is currently presented as not more than 8.79 TPD. Even that value is overstated since adjustments needed to fully account for the findings of the AQMD's third-party refinery expert, Norton Engineering, would reduce the shave for BARCT equivalency to not more than 7.94 TPD.[20] Thus, RECLAIM facilities would have greater costs under the Staff proposal than would have been incurred under a command-and-control program. And contrary to H&SC §39616(c)(7), AQMD has failed to demonstrate that the RECLAIM program as amended will not result in disproportionate impacts, measured on an aggregate basis, to those stationary sources included in the program as compared to other permitted stationary sources in the District's plan for attainment. RECLAIM program sources have already reduced NOx emissions by 69% since 1994, whereas command-and-control stationary sources have only reduced NOx emissions by about 44% during that same period.[21] The BARCT levels being proposed by AQMD Staff generally represent performance levels that have not been demonstrated as broadly achievable for the source categories in question. Furthermore, these performance levels go well beyond the command-and-control standards adopted by AQMD under Regulation XI (i.e., the District's command-and-control program), and are well beyond BARCT determinations made by other major California air agencies administering command-and-control programs (e.g., SJVAPCD, BAAQMD, etc.).

[19] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
[20] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18.
[21] "RECLAIM Sources" data is computed from data presented in AQMD's RECLAIM Audit Report (March 2015). Command-and-control stationary sources NOx emissions is computed from data presented in AQMD Air Quality Management Plans (1997, 2003, 2007, 2012) and AQMP NOx RECLAIM Working Group Meeting #5, Agenda Item #3.

Page 2-2, Section 2.2 Project Objectives (continued)	Next, the Draft PEA suggests an objective to "modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment." That is not consistent with the project description contained in the Notice of Preparation issued 4 December 2014,[22] nor is it consistent with project description contained in the Initial Study.[23] Specifically, neither the NOP Project Description nor the Initial Study Project Description included any reference to modifying "the RECLAIM trading credit (RTC) "shaving" methodology" in the description of the project or the project objectives. And this is also inconsistent with the objectives approved by the Governing Board under Control Measure CMB-01. For these reasons, all references to "modifying "the RECLAIM trading credit (RTC) "shaving" methodology" should be removed from the Draft PEA.
Page 2-2, Section 2.2 Project Objectives (continued)	This section also suggests an objective "Achieve NOx emission reductions to assist in attaining the NAAQS." This is also not consistent with the Project Description contained in the Notice of Preparation issued 4 December 2014,[24] or the description contained in the Initial Study Project Description.[25]

[22] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."

[23] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.

[24] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."

[25] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.

Page 2-6, 4th paragraph	The Draft PEA states "the proposed project is estimated to reduce four tons per day of NOx emissions starting in 2016 because the amount of unused RTCs in the NOx RECLAIM program over the past five years (e.g., from 2009 to 2013) ranged from five tpd to eight tpd, demonstrating that there is enough cushion to support reduction of four tpd in 2016." While the quantities of "unused" RTCs are a matter of historical record, Staff has provided no evidence to support that supposition that the RECLAIM market has "enough cushion to support reduction of four tpd in 2016." And if this was just a reduction of unused RTCs, that would not equate to an emissions reduction in 4 TPD. The Draft PEA needs to be revised to include a market analysis to support that supposition or this statement should be deleted.
Page 2-6, 4th paragraph (continued)	The Draft PEA goes on to state "it could take from two to four years for the affected facilities to plan, obtain permits, and install air pollution control equipment or modify existing equipment in response to the proposed project." According to information from WSPA members, this estimate is too short.[26] While some individual projects might be complete able in 2-4 years, the proposed project would require dozens and dozens of emission control projects to be completed. For the refinery sector, such projects would need to be planned, engineered, and sequenced for construction in consideration of unit turnaround schedules. WSPA members report that completion of all needed projects for the proposed project would likely require not less than eight (8) years. The Draft PEA should be revised to reflect this timetable and the Proposed Amended Rules and PDSR should be similarly adjusted.
Page 2-9, PAR 2005 Requirements for New or Relocated RECLAIM Facilities – Subdivision (b)	The AQMD Staff have yet to provide a complete description of the amendments to this rule. AQMD Staff have also not obtained U.S. EPA approval that such amendments would even be approvable into the State Implementation Plan (SIP). The Draft PEA and PAR 2005 should be revised to reflect these important details after AQMD Staff have obtained the U.S. EPA approval needed for such amendments to be legal.
Page 2-10, top of page	The Draft PEA states "Further, only 44 facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact." The Draft PEA should be revised to present supporting analysis demonstrating how this conclusion was reached.
Page 3.2-34, 2nd paragraph, GHG Tailoring Rule	This section should be revised to note that the courts vacated significant portions of the GHG Tailoring Rule. The applicability criteria as described in the Draft PEA are not consistent with current regulations.
Page 4.1-3, Section 4.1.3.1	The Draft PEA states "Because each affected facility is located in heavy industrial areas, the construction equipment is not expected to be substantially discernable from what exists on-site for routine operations and maintenance activities. Further, the construction activities are not expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities are expected to occur within the confines of each existing facility and are expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility."

[26] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.

	This statement oversimplifies the range of physical settings existent for RECLAIM facilities. In actuality, some refinery or non-refinery RECLAIM facilities are located areas where additional vertical obstructions from cranes or new emission control structures could be "discernable" and may adversely impact views and aesthetics resources for adjacent communities. The Draft PEA should be revised to clarify the range of settings which would be impacted by the proposed project and acknowledge the range of potential impacts associated with the proposed project.
Page 4.2-2, Table 4.2-1 Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category	As shown in this table, the Draft PEA states that Staff has assumed 74 SCRs would be installed on Refinery Process Heaters and Boilers under the proposed project. Staff does not explain the basis for this value, which conflicts with the Preliminary Draft Staff Report (PDSR). The PDSR suggests that the proposed project would result in 76 SCRs (25 upgraded, 51 new) for refinery heaters and boilers,[27] in which case the Draft PEA would be understating the potential project impacts. It should also be noted that AQMD's third-party refinery sector expert, Norton Engineering, found that only 48 refinery heaters and boilers could be cost effectively retrofit with new or upgraded SCRs.[28] Staff have done nothing to reconcile this discrepancy which is material. The Draft PEA must be revised to clarify the technical basis for the assumed emission controls outcome and associated potential impacts to the environment. The Draft PEA should also explain how emission controls which are not cost effective, according to AQMD's own third-party expert, will be implemented.
Page 4.2-4, Section 4.2.3.1, first paragraph	The Draft PEA states "Further, operators at each affected facility who construct NOx control equipment that utilize chemicals as part of the NOx control equipment operations, such as a new ammonia or caustic storage tank, may also need to build a containment berm large enough to hold 110 percent of the tank capacity in the event of an accidental release, pursuant to U.S. EPA's spill prevention control and countermeasure regulations." While other regulations and good engineering practices would require containment features for these tanks, the Spill Prevention Control and Countermeasure (SPCC) regulations actually don't apply to ammonia or caustic storage vessels. The Draft PEA should be clarified accordingly.
Page 4.2-7, last paragraph	The Draft PEA states "if a particular technology was identified as having a cost that exceeds $50,000 per ton, this CEQA analysis assumed that the facility operator would not install this type of air pollution control technology in response to the project." This statement is inconsistent with the project objectives which require compliance with the California Health & Safety Code. The $50,000 threshold fails in this regard. Under H&SC§39616(c)(1), the RECLAIM program is required to result in "an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations** and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment." AQMD Staff has failed to demonstrate that the proposed amended RECLAIM program will be **at equivalent or less**

[27] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, Table B.10.
[28] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, Table B.9.

	cost compared with current command and control regulations. On the contrary, Staff's proposed $50,000 cost effectiveness threshold for this RECLAIM rulemaking is more than double the cost threshold used by AQMD for command-and-control rules (i.e., $22,500 per ton[29]). This clearly imposes a greater cost on RECLAIM sources than would be incurred under command and control regulations. The Draft PEA and Proposed Amended Rules must be revised is be consistent with the project objectives and all applicable H&SC requirements.
Page 4.2-8, Section 4.2.3.1, first paragraph	The Draft PEA states "In order to operate SCR and UltraCat technology, ammonia is necessary and, as such, tanks to store ammonia would also need to be installed. The size of each ammonia tank needed to operate the SCR units and one UltraCat filtration unit have been estimated to range between 2,000 and 11,000 gallons in capacity." While this statement may be appropriate for characterizing new tanks which are likely to handle aqueous ammonia, it ignores the fact that some existing ammonia tanks are used to store anhydrous ammonia. The PEA should be revised to address this description. Staff should consider whether this condition requires revision of the offsite consequence analysis presented in the Draft PEA.
Page 4.2-8, Section 4.2.3.1, 5th paragraph	The Draft PEA states "From a construction point of view, the installation of a NOx control technology at a refinery is a complex process. For example, if a facility operator chooses to install NOx control equipment, time will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential control equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and scheduling contractors and workers. The amount of lead time can vary from six months (e.g., for a SCR for refinery/boiler heater or gas turbine) to up to 18 months for a scrubber (either a WGS or DGS)." AQMD permitting for new emission controls can easily take as much as 18 months for Title V facilities. This could easily increase the amount of lead time a company requires to 2-3 years. Some of the pre-construction activities cannot be conducted until the Permit to Construct has been issued.
Page 4.2-11, top of page	The Draft PEA states "…the analysis also includes an analysis of the overlapping impacts spread out over a five- and seven-year period." According to information from WSPA members, this estimate is too short. While some individual projects might be complete able in 2-4 years, the proposed project would require dozens and dozens of emission control projects to be completed. For the refinery sector, such projects would need to be planned, engineered, and sequenced for construction in consideration of unit turnaround schedules. WSPA members report that completion of all needed projects for the proposed project would likely require not less than eight (8) years.[30] The Draft PEA should be revised to reflect this timetable and the Proposed Amended Rules and PDSR should be similarly adjusted.

[29] AQMD, 2012 Air Quality Management Plan (AQMP), December 2012.
[30] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.

Page 4.2-13, 1st paragraph Combined Construction Emissions From Non-Refinery and Refinery Facilities	The Draft PEA does not disclose the assumed basis for construction impact estimates. Are these impacts based on construction of emission controls to deliver 8.79 TPD (i.e., BARCT equivalency), or has Staff assumed construction sufficient to deliver the proposed 14 TPD of emission reductions (i.e., beyond BARCT equivalency)? The amount of construction activity for modification of existing SCRs will be different than the activity needed for entirely new SCR installations. The Draft PEA must be revised to fully disclose the technical basis of this analysis so the public can understand whether the impacts presented are complete.
Page 4.2-13, last paragraph Combined Construction Emissions From Non-Refinery and Refinery Facilities	The Draft PEA notes "…it is likely that only minimal, if any, construction activities would occur at any refinery facilities during 2016." This is exactly why the Staff proposal to remove four (4) TPD of RTCs in 2016 is too much, too fast. Staff has provided no evidence to support that supposition that the RECLAIM market has "enough cushion to support reduction of four tpd in 2016."
Page 4.2-18, 1st paragraph	The Draft PEA states "Implementation of the proposed project is expected to result in direct air quality benefits from the reduction of 14 tons per day of NOx RTCs by 2022. Because of the RECLAIM market system, the actual reduction in NOx emissions each year may be less than the reduction in RTC holdings imposed by the project." This statement conflicts with Page 1-1, 4th paragraph. Please see our comment to that prior statement.
Page 4.2-20, Refinery Facilities	This section presents impacts from operation of the proposed project for refinery facilities in the South Coast air basin. The Draft PEA does not disclose the assumed basis for these impact estimates. Are these impacts based on operation of emission controls to deliver 8.79 TPD (i.e., BARCT equivalency), or has Staff assumed operations sufficient to deliver the proposed 14 TPD of emission reductions (i.e., beyond BARCT equivalency)? The Draft PEA should be revised to explain the basis of the technical analysis so the public can understand whether the impacts presented are complete.
Page 4.2-22, 1st paragraph	The Draft PEA states "Ammonia slip is limited to five parts per million (ppm) by permit condition." This is an oversimplification since some existing SCRs are permitted with higher ammonia slip limits. These existing units may not be required to open their permits, in which case they could continue to operate with higher than 5 ppmv ammonia slip performance. Furthermore, the Draft PEA analysis of ammonia slip for new SCR installations depends on physical conditions which the Staff analysis explicitly omitted from the project description (e.g., use of Ammonia Slip Catalysts or ASC) despite recommendations by the AQMD's third-party expert, Norton Engineering, to use ASC.[31] Without the ASC, ammonia slip from individual devices could be as great as 20 ppmv, but the draft PEA underestimates the ammonia slip by assuming it will universally be 5 ppmv. However, existing SCRs are not necessarily subject to those permit

[31] Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Table 2-3.

	conditions, and thus, ammonia slip of up to 20 ppmv should be considered in the health risk assessment for ammonia emissions.[32] The Draft PEA should be revised to more accurately reflect the range of ammonia slip conditions which could exist. Importantly, the screening Health Risk Assessment results presented in the Draft PEA would need to be revised to reflect that broad range of ammonia slip performance.
Section 4.2.4, Cumulative Air Quality Impacts	The Draft PEA does not discuss the potential secondary impacts on air quality associated with increased emissions of ammonia from the numerous SCRs mandated by this rulemaking. Ammonia is a precursor to PM2.5 formation for which the South Coast AQMD is in nonattainment, so the PEA should consider whether additional ammonia emissions would represent a cumulatively considerable impact.
Page 4.2-26, 1st full paragraph	The Draft PEA states "…based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, is anticipated to bring the District into attainment with all national and most state ambient air quality standards by the year 2023." This statement is at best incorrect. A significant portion of the control strategy presented in the 2012 AQMP was still 182(e) "black box" measures which have not been defined.
Chapter 5, Alternatives	In this section, the Draft PEA presents 5 alternatives to the proposed project, but except for Alternative 4 (No Project) and Alternative 3 (Industry Approach), all other alternatives propose 14 TPD or more of NOx emission reductions. Given that the proposed project has remaining significant environmental effects with the proposed project at 14 TPD, the failure to include any additional alternatives other than Alternative 3 (Industry Approach) at a lesser reduction of NOx emissions does not satisfy CEQA's requirement for a "reasonable range of alternatives." In addition, the Draft PEA repeatedly claims that the impacts from the alternatives are "not quantifiable" for unspecified reasons. But these figures are not unknowable. In most cases, Staff could have easily made bounding or other technical assumptions to complete the quantification to allow the public to understand how the impacts from the alternatives compare to the Staff's proposed project. The Draft PEA must be revised to include this additional technical detail.

[32] Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Tables 4.2-18 and 4.2-21.

RESPONSES TO COMMENT LETTER #5
(Phillips 66 Company – October 6, 2015)

5-1 This comment supports the sentiments expressed in Comment Letter #2. While Comment Letter #2 was submitted with four additional documents that are included in this appendix, Comment Letter #5 only provided a copy of the first two documents submitted as part of Comment Letter #2 (e.g., the main letter dated October 6, 2015 and Attachment 1 of Comment Letter #2) as reference. See Responses to Comment Letter #2.

Comment Letter #6

VIA ELECTRONIC MAIL

October 6, 2015

Ms. Barbara Radlein
Program Supervisor, CEQA Special Projects
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: NOx RECLAIM INDUSTRY COALITION COMMENTS ON DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDMENTS TO REGULATION XX

Dear Ms. Radlein:

The NOx RECLAIM Industry Coalition ("the Coalition") consisting of the industry trade associations listed below submits these comments on the Draft Program Environmental Assessment ("DPEA") for Proposed Amendments to Regulation XX.

California Asphalt Pavement Association (CalAPA)
California Construction & Industrial Materials Association (CalCIMA)
California Council for Environmental and Economic Balance (CCEEB) 6-1
California Manufacturers and Technology Association (CMTA)
California Metals Coalition (CMC)
California Small Business Alliance (CSBA)
Regulatory Flexibility Group (RFG)

Southern California Air Quality Alliance (SCAQA)
Western States Petroleum Association (WSPA)
Los Angeles Business Federation (BizFed) 6-1 Con't

I. PROJECT DEFINITION NOT CONSISTENT WITH THE PROJECT ANALYZED

The Project is defined as the amendment of Regulation XX to implement a reduction in NOx RECLAIM Trading Credits ("RTCs") of 14 tons per day. However, the project analyzed is only the installation of BARCT at various facilities. These are not the same things. The construction activities related to the potential installation of BARCT at various facilities is only a subset of the proposed Project, and represents only 8 tons per day of the proposed 14 tons per day reduction. The cost of removing the additional 6 tons per day to get to 14 tons per day must be included in this analysis. 6-2

The project as actually proposed and defined would virtually eliminate the NOx RTC market. The RECLAIM program is a cap-and-trade program that relies on the availability of RTCs to provide structural buyers a source of credits, provide for NSR holdings required by RECLAIM NSR rules, and provide for construction of new facilities and expansion of existing facilities. The removal of 14 tons per day of NOx RTCs will adversely impact all of these uses but there is no analysis even attempted in the DPEA of such impacts. Since the DPEA only analyzes a subset of the entire project, it fails to comply with CEQA's requirement to evaluate impacts from the "whole of the action" being proposed. CEQA Guidelines §15378(a). It appears that removal of 14 tons per day of NOx RTCs and the potential destruction of the NOx RTC market is "assumed" to have no effect.

II. REMOVAL OF 14 TONS PER DAY OF NOX RTCS WOULD HAVE SIGNIFICANT IMPACTS

There are potential impacts on energy supply and reliability in the event insufficient RTCs are available to provide for increased energy demand (which will be exacerbated by District plans, as expressed in ongoing air quality planning activities related to the 2016 AQMP, to electrify large segments of the Southern California industrial, service, and residential sectors). There is no analysis whatsoever of the potential impacts on structural buyers or any other RECLAIM participants (including many NOx RECLAIM Industry Coalition members), other than those who the District expects to have to install emission control equipment. 6-3

III. USE OF A PROGRAM ENVIRONMENTAL ASSESSMENT IS INAPPROPRIATE WHEN PROJECT LEVEL IMPACTS ARE BEING ASSESSED 6-4

The PEA states that it is a program level document. However, it only evaluates BARCT related construction activities which are really "project level" activities. The DPEA should include a project level review of impacts, which it does not do.

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IV. THE PROPOSED PROJECT IS INCONSISTENT WITH THE STATED OBJECTIVE OF COMPLYING WITH HEALTH AND SAFETY CODE SECTION 39616

The stated objective of the Project is to comply with the requirements in Health and Safety Code §39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing BARCT. However, compliance with that section also requires that RECLAIM emission reductions be equivalent or greater than reductions that would have resulted under command and control at equivalent or less cost compared with command and control. The Project fails to meet the cost equivalency of that requirement. The District uses a cost-effectiveness figure of $50,000 per ton for RECLAIM BARCT and $22,500 per ton for command and control BARCT. This is inconsistent with state law and thus with the stated objective of cost equivalency and results in a reduction of RTCs that will necessitate emission reductions beyond what can be achieved by application of BARCT (relative to a command and control rulemaking). Furthermore, only a portion of the shave has received any cost estimate at all. SCAQMD has only provided cost estimates for 8.8 tons per day (related to installing technology) of a 14 tons per day shave. Obviously shaving beyond the portion of the shave attributable to technology will exceed costs for equivalent command and control regulations. 6-5

There is also no analysis of potential business closures as a result of such a severe shave that would reduce the availability and increase the cost of RTCs. While the District has noted that the number of facilities in RECLAIM has dropped from 392 facilities to 276, there has been no effort to evaluate the significance of this change and whether the proposed 14 ton per day shave would be consistent with the requirements of §39616(c)(4). That section requires that the RECLAIM program "not result in a greater loss of jobs or more significant shifts from higher to lower skilled jobs, on an overall districtwide basis, than that which would exist under command and control air quality measures that would otherwise have been adopted as part of the district's plan for attainment."

V. THE DPEA FAILS TO ANALYZE A REASONABLE RANGE OF ALTERNATIVES THAT COULD MEET THE OBJECTIVE OF THE PROJECT WITH LESSER IMPACTS

The PEA fails to analyze whether alternatives to the 14 ton per day proposed shave could also meet the objective of obtaining emissions reductions from the RECLAIM universe equivalent to the BARCT reductions identified by staff. For example, staff could have reviewed past shaves to determine the ratio between the amount shaved and the amount of actual emission reductions that occurred from the RECLAIM universe. This would at least provide an empirically derived alternative to the District's 14 ton per day NOx shave, which is beyond any previously imposed shave and would seem to be (empirically) much greater than necessary to achieve 8.7 tons per day of actual emission reductions (actually 8 tons per day after the 0.7+ tons per day are given back on BARCT as a result of the Norton Engineering kerfuffle). If the BARCT reduction could be achieved with less than 14 tons per day of RTC reductions, it would significantly reduce, and possibly avoid, many if not all of the impacts of the 14 ton per day proposed reduction. 6-6

3

VI. CONCLUSION

In summary, the PEA needs to be redone to address all of the potential project impacts, not just the construction related impacts, and additional alternatives can and should be identified that could achieve the project's objective while avoiding the significant impacts and inconsistency with Health and Safety Code Section 39616 associated with a 14 ton per day shave. 6-7

Respectfully,

Curtis L. Coleman
Executive Director, Southern California Air Quality Alliance
On behalf of the NOx RECLAIM Industry Coalition

cc: Dr. Phil Fine, SCAQMD

4

RESPONSES TO COMMENT LETTER #6
(Curtis L. Coleman on behalf of
the NOx RECLAIM Industry Coalition – October 6, 2015)

6-1 This comment introduces the parties represented by the letter. No response is necessary.

6-2 The project consists of the proposed amendments to Regulation XX, which includes a proposal to reduce NOx RTC holdings by 14 tpd by 2023. Based on the analysis, SCAQMD staff's opinion is that the 14 ton per day reduction is necessary to implement the actual BARCT reduction because of the substantial number of unused RTCs in the market. As explained in Chapter 4, Subchapter 4.0 of the Draft PEA, the installation and operation of new or modified existing NOx emission control equipment at 20 facilities was identified as the only portion of the entire proposal that is expected to result in physical effects that may affect the environment, since they were the only ones identified that would install pollution control equipment as a result of the proposed shave. According to CEQA Guidelines §15126.2, "An EIR shall identify and focus on the significant environmental effects of the proposed project. In assessing the impact of a proposed project on the environment, the lead agency should normally limit its examination to changes in the existing physical conditions in the affected area as they exist at the time the notice of preparation is published..." For this reason, the analysis in the PEA focuses on the physical effects that may occur as a result of constructing new or modifying existing NOx control equipment and operating the equipment once constructed.

Because of the substantial excess of RTCs in the market, SCAQMD staff disagrees with the assertion about "the potential destruction of the NOx RTC market." SCAQMD staff's proposal includes allowing for growth between now and 2023, allowing a compliance margin of 10 percent, and providing an additional amount of RTCs to account for BARCT uncertainties. Therefore, no significant adverse impacts on construction of new facilities and expansion of existing facilities is expected. In any event, SCAQMD staff is proposing to increase the RTC price trigger to reevaluate the RECLAIM program from $15,000 per ton to $22,500 per ton. SCAQMD staff expects that there will still be enough RTCs to support a functioning market. After the shave, there will still be nearly as large a margin as there was before the shave, in terms of percentage of actual emissions. Moreover, while economic or social information may be included in an EIR, it is not a requirement. The costs of removing the unused RTCs (5.23 tpd, not the 6 tpd asserted by the commenter) is not an environmental impact. Further, economic or social effects of a project shall not be treated as significant effects on the environment. Instead, the focus of the analysis shall be on the physical changes. [CEQA Guidelines § 15131 (a)]. For this reason, the analysis in the PEA does not address the costs associated with achieving the proposed NOx emission reductions. Instead, as explained in Response 2-19, a socioeconomic analysis has been conducted and the analysis and findings are presented in a separate document, the Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), initially published on September 9, 2015 and revised on October 6, 2015 and November 4, 2015[16].

The socioeconomic analysis addresses the socioeconomic impacts relating to the availability of RTCs to provide structural buyers (e.g., facilities where no controls were identified in the 2015 BARCT analysis) a source of credits and to provide for NSR holding requirements under SCAQMD Regulation XIII - New Source Review. In particular, the socioeconomic analysis describes the potential incremental costs of RTCs needing to be purchased by structural buyers (although that cost will be a profit to those who have RTCs to sell) as well as quantifying the potential "loss in value" due to removal of excess unused RTCs. In terms of compliance costs, the socioeconomic analysis addresses the potential cost impacts that may result from the construction and operation of new or modified NOx emissions control equipment that may be installed as a result of the proposed project.

6-3 SCAQMD staff has consulted with the power-producing sector, which uniformly agrees that any potential shortage of RTCs may only occur during rare events where electrical demand far exceeds normal operations. The potential increase in energy demand has been addressed in the staff proposal, which provides several safeguards that would provide electricity generating facilities (EGFs) with an adequate amount of credits. The safeguards include access to non-tradable/non-usable RTCs with a faster 3-month trigger. The 12-month trigger remains, but the threshold dollars per ton level is now $22,500. In the event of a State of Emergency declared by the Governor, EGFs would have access to non-tradable/non-usable credits. If these credits are exhausted, EGFs would also have access to the credits in the Regional NSR Holding Account. Furthermore, EGFs now have the option to exit the RECLAIM program if they meet certain requirements. With this option, an EGF would no longer be concerned with the possibility of an RTC shortage, even though staff feels that there will not be such a shortage if BARCT controls are implemented for those applicable facilities that were analyzed. Resolution language will be prepared that directs staff to monitor the power-producing sector for trends in power consumption as electricity demand potentially increases. With these safeguards in place, no adverse impact on electrical reliability is anticipated.

In addition, Chapter 4, Subchapter 4.3 of the PEA, contains an energy impact analysis which identifies the net effect on energy resources relating to the construction and operation of new or modified NOx air pollution control equipment that may occur as a

[16] SCAQMD, Draft Final Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), November 4, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaim_dfsocio_110415.pdf?sfvrsn=2.
SCAQMD, Revised Draft Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), October 6, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/reclaim_revisedsociodraft.pdf?sfvrsn=2
SCAQMD, Draft Socioeconomic Report for Proposed Amendments to Regulation XX - Regional Clean Air Incentive Market (RECLAIM), September 9, 2015. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/reclaim_sociodraft_090915.pdf?sfvrsn=4

result of implementing the proposed project. The energy analysis does not contain an analysis of the effects of structural buyers or other RECLAIM participants that have been demonstrated to not have a cost-effective option for controlling NOx emissions further because neither of these groups have been demonstrated to have an increased demand for energy as a result of implementing the proposed project. If this comment is intended to refer to electricity generating facilities, the above-cited provisions of the amendments are designed to address the needs of this sector.

The electrification of "large segments of the Southern California industrial, service, and residential sectors" as part of ongoing air quality planning activities related to the 2016 AQMP is not part of the proposed project. As noted above, SCAQMD staff has proposed provisions in the amendments to address the electric utility sector's foreseeable needs. At this point, it would be speculative to predict increased needs as a result of increased electrification. Nevertheless, staff will include a Governing Board resolution to address this long-term issue if it ever arises.

The 2016 AQMP is currently under development and on a separate schedule from the proposed project. As the 2016 AQMP development process moves forward, a separate CEQA analysis of the effects of what is proposed for the 2016 AQMP will be conducted and presented as part of a Program EIR which will provide multiple opportunities for review and comment by the public, stakeholders, and other interested parties.

See Response 6-2 regarding analysis of potential impacts on structural buyers and other RECLAIM participants.

6-4 As part of the rule development process for amending Regulation XX for SOx RECLAIM in October 2010, SCAQMD staff originally intended to prepare an Environmental Assessment (EA) for the project. However, during the public review and comment period of the NOP/IS for the project, the SCAQMD received a comment suggesting that a program level CEQA analysis be conducted instead. Going forward at that time, SCAQMD staff agreed with the suggestion, and subsequently prepared a Program Environmental Assessment (PEA). The decision to prepare a Draft PEA was based on the SOx RECLAIM project: 1) being connected to the issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program [CEQA Guidelines §15168 (a)(3)]; and, 2) containing a series of actions that can be characterized as one large project and the series of actions are related as individual activities that would be carried out under the same authorizing regulatory authority and having similar environmental effects which can be mitigated in similar ways [CEQA Guidelines §15168 (a)(4)[17]]. The analysis in the Final PEA for SOx RECLAIM, evaluated the physical effects of installing and operating new or modified air pollution control equipment to reduce SOx emissions for the various affected facilities.

[17] SCAQMD, Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), October 2010; SCAQMD No. 06182009BAR, State Clearinghouse No: 2009061088, page 1-3. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2010/final-program-environmental-assessment-for-proposed-amended-regulation-xx.pdf?sfvrsn=4.

The SOx RECLAIM PEA allowed the consideration of broad policy alternatives and program-wide mitigation measures at a time when an agency has greater flexibility to deal with basic problems of cumulative impacts. [CEQA Guidelines §15168 (b)(4)]. Further, the SOx RECLAIM PEA played an important role in establishing a structure within which CEQA review of future related actions could effectively be conducted.

Similarly, for the current proposed amendments to Regulation XX for NOx RECLAIM, SCAQMD staff prepared a Draft PEA which also evaluated the physical effects of installing and operating new or modified air pollution control equipment, but to reduce NOx instead of SOx emissions for the various affected facilities. Seeing no fundamental difference between the SOx and NOx RECLAIM projects relative to the possibility for future project-level analysis, a program level analysis was determined to be appropriate and was conducted for the proposed NOx RECLAIM project. The fact that the PEA evaluates the "BARCT related construction activities" that are projected to occur does not mean that a project-level, instead of a programmatic analysis, was conducted. Moreover, in accordance with CEQA Guidelines §15168 (c)(5), a program analysis should deal with program impacts as specifically and comprehensively as possible and the PEA did so.

The PEA estimates, using engineering assumptions and the best data available, what the potential impacts may be. However, in recognition that the potential future actions conducted by individual facility operators may actually contemplate activities that could create resulting environmental impacts that may be different or new from what was analyzed in the PEA, individual facility operators will be afforded the opportunity to rely upon the PEA if it covers impacts of their project, as part of conducting a future CEQA analysis of any actual projects proposed subsequent to the proposed adoption of the amendments to the NOx RECLAIM program.

This comment also states that the PEA should include a project-level review of impacts, while at the same time stating that the PEA only evaluated project-level impacts. SCAQMD staff assumes the commenter meant to say that the PEA should have included a program-level review of impacts. The PEA did so by including a comprehensive analysis of expected environmental impacts of the proposed amendments, as well as the impacts of the alternatives considered in the PEA, specifically including the impacts of the Industry Approach (Alternative 3). SCAQMD staff does not expect physical impacts to occur beyond those identified in the PEA. The comment does not provide substantial evidence of additional physical impacts on the environment. See also Response 2-16 for an explanation as to why the PEA conducts a program level analysis and not a project level analysis.

6-5 The comment states that the proposed project does not comply with Health and Safety Code §39616, which requires a finding that the RECLAIM program result in equivalent or greater emission reductions at equivalent or less cost compared with command-and-control, because the analysis used a $50,000 per ton cutoff for RECLAIM BARCT while the SCAQMD uses a $22,500 per ton cost-effectiveness for command-and-control BARCT.

As of the third quarter 2015, the SCAQMD's BACT cost-effectiveness is $27,107 per ton for minor sources, whereas most of the RECLAIM sources that will be expected to install BARCT controls, including all of the refineries, are major sources. Health and Safety Code §39616 calls for a comparison with what would have been achieved by the RECLAIM sources themselves under command-and-control, not what is achieved by some other sources. Moreover, the $50,000 figure does NOT mean that the cost-effectiveness of the proposed amendments is $50,000 per ton. Instead, the $50,000 figure was used to eliminate candidate BARCT technologies from consideration. None of the technologies actually identified as BARCT exceeds the mid to upper $30,000s per ton, and then only for the refineries. In fact, the average cost-effectiveness for the proposed amendments (total costs divided by total tons) is only $13,615 per ton. Thus, the proposed project satisfies the findings set forth in Health and Safety Code §39616, although it is not legally required to do so. Finally, the SCAQMD Governing Board has adopted rules for smaller sources which have cost-effectiveness values ranging up to the upper $20,000s and lower $30,000s per ton, such as Rule 1146.1, Rule 1147, and Rule 1110.2. SCAQMD staff has already explained in the socioeconomic analysis why the costs to buyers of purchasing RTCs are cancelled out on a programmatic basis by the gains to the sellers of RTCs, and why the "value" of shaved, unneeded RTCs cannot be compared to command-and-control because there are no RTCs, and thus no such "value" to begin with, under command-and-control.

According to CEQA Guidelines §15125, an EIR must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the Notice of Preparation (NOP) is published and this environmental setting normally constitutes the baseline physical conditions by which a lead agency determines whether an impact is significant. At the time the NOP was published, SCAQMD staff identified 275 facilities that are currently in the NOx RECLAIM universe of sources and these 275 facilities are considered to be part of the existing environmental setting or baseline. For this reason, the reduction in the number of facilities that participate in the NOx RECLAIM program over the years from 392 to 275 and any corresponding loss of jobs or shift from higher to lower skilled jobs is not a part of the proposed project that would require an analysis in this PEA.

Macroeconomic factors could have played a far more pivotal role in the changes to the composition of the RECLAIM universe. For example, RECLAIM was adopted in 1993 shortly after the 1990-91 recession which severely affected Southern California's aerospace industry triggering protracted ripple effects throughout the entire regional economy. This event, combined with the national trend of a declining manufacturing sector, likely has contributed to business shutdowns and relocations. The 2001 and the more recent 2007-2009 economic recessions also impacted business operations to various degrees. Other factors such as business consolidations and mergers could also have affected the RECLAIM universe.

Moreover, there is no evidence that RECLAIM was in any way the cause of a significant number of facilities shutting down. Each year, the SCAQMD staff prepares a program audit and report to the SCAQMD Governing Board pursuant to Rule 2015 (b) which includes the facilities that have shut down and the reasons given for their shutdown. SCAQMD staff has reviewed all annual program audits and concluded that although about 178 facilities have shut down (while about 50 new facilities have entered the market), only three facilities identified RECLAIM as a reason for their shutdown and only 10 identified environmental regulations other than RECLAIM as a reason for their shutdown. Since the majority of facilities that shutdown was not due to RECLAIM, any resulting environmental impacts form the shutdowns are also not caused by RECLAIM. Based on this past history, and the fact that the market will continue to have a comparable level of excess unused RTCs even after the shave is implemented as it has had historically, no significant number of facility shutdowns and thus no resulting significant environmental impacts can be predicted. See also Response 2-21.

6-6 Two opportunities (e.g., during the 57-day public review and comment period of the NOP/IS and at the CEQA scoping meeting) were provided to commenters to suggest ways of crafting the various alternatives to be analyzed in the PEA. The SCAQMD staff received several suggestions for alternatives, with a consensus to analyze an "industry" alternative which was included in the PEA as Alternative 3. In addition, four other alternatives, one of which was the no project alternative (e.g., Alternative 4), were analyzed in the PEA. When considering and discussing alternatives to the proposed project, an EIR need not consider every conceivable alternative to a project but instead consider a reasonable range of potentially feasible alternatives that will foster informed decision making and public participation. [CEQA Guidelines 15126.6 (a)]. For this reason, the PEA analyzes five alternatives to the project. Aside from Alternative 4, the no project alternative, the remaining alternatives each contains varying approaches to the NOx RTC shave with varying degrees of potential NOx emission reductions applicable to various sources. As such, SCAQMD staff believes that the PEA contains a reasonable range of potentially feasible alternatives, thus, no additional alternatives are necessary or required.

The suggestion by the commenter to review past shaves and to ratio the amount between the amount shave and the actual emission reductions has been conducted as part of rule development. The data review conducted during rule development as part of the BARCT equivalency demonstration concluded that past NOx RTC shaves were ineffective at reducing emissions. Because this data review comprised an important impetus to demonstrate the need for the proposed project (e.g., the need for the NOx RTC shave), the suggested ratio analysis does not qualify as an alternative to the project. With respect to Norton Engineering, it is noteworthy that Norton Engineering agreed with SCAQMD staff regarding the appropriate BARCT levels for all categories except boilers/heaters, which amounted to about 0.35 tpd difference in the total shave. SCAQMD staff increased this BARCT uncertainty factor to over 0.8 tpd to account for any other potential uncertainty.

This comment states that the PEA fails to analyze whether alternatives to the proposed 14 ton per day shave could meet the objective of obtaining equivalent emissions reductions to the BARCT reductions identified by SCAQMD staff. A CEQA document is only required to consider a range of reasonable alternatives to the project which would feasibly obtain most of the basic objectives of the project but would avoid or lessen any of the significant effects of the project. [CEQA Guidelines §15126.6 (a)]. The PEA meets this test. The comment suggests that the PEA should look at other ways of achieving emission reductions equivalent to the BARCT reductions identified by SCAQMD staff. Assuming that this comment means alternative ways of achieving actual emission reductions to result in remaining emissions equivalent to those in the staff proposal, this would still require reducing actual emissions by the same amount as the staff proposal. Since actual emissions are reduced by installing and operating additional control equipment, the environmental effects of such an alternative would be the same.as those analyzed in the PEA.

The commenter suggests that SCAQMD staff could have looked at past shaves to determine the ratio between the amount shaved and the amount of actual emission reductions that occurred from the RECLAIM universe (presumably to derive an alternative shave amount). The problem with this approach is that there is no fixed ratio between actual emissions reductions and RTCs shaved. Comment Letter #1 suggests that between 2005 and 2011, a comparison of 0.83 tpd emission reductions to 1 tpd RTC reductions would result in a ratio of 0.83, but that included two years (2005 - 2006) when there were actual emission reductions, but no RTC shave. If the analysis looked at the actual shave years (2007 through 2011), the ratio would be a comparison between 4.09 tpd reductions to 7.66 tpd RTCs reduced, or 0.53 instead of 0.83. Moreover, if there were a larger amount of available unneeded RTCs, such as the 73 percent projected to occur with the Industry Approach (or even more if the Industry Approach used the 6.6 tpd target) it is likely that facilities would not significantly reduce actual emissions but would simply surrender unneeded RTCs. Thus, no fixed ratio can be determined to allow the suggested alternative approach.

6-7 As explained in more detail in Response 6-2, the PEA analyzes both the construction and operational impacts of the project elements that may result in physical changes to the environment. The commenter has not identified any new aspects of the proposed project that would cause potential significant impacts that should be included and analyzed in the PEA. Thus, SCAQMD staff disagrees that the PEA needs to be "redone."

With regard to the analyzing additional alternatives in the PEA, see Response 6-6.

Comment Letter #7

NRDC

October 06, 2015

Via Electronic Mail

Ms. Barbara Radlein
South Coast Air Quality Management District
bradlein@aqmd.gov

Re: Program Environmental Assessment
Proposed Amended Regulation XX (RECLAIM)

Dear Ms. Radlein,

The following comments are provided by the Natural Resources Defense Council, Sierra Club, Earthjustice, and Communities for a Better Environment regarding the South Coast Air Quality Management District Program Environmental Assessment (PEA) for Proposed Regulation XX (RECLAIM). 7-1

The RECLAIM project has not proven its value as a cheaper or more efficient way to reduce NOx emissions in the South Coast Air Basin compared to a command and control model. If it is to be retained, it needs to be substantially strengthened and accelerated. 7-2

With respect to the PEA, there are three major flaws, all of which flow from the PEA's overly-narrow reading of its own project objectives: failure to include ending the RECLAIM program as an alternative, failure to choose the environmentally superior alternative among the alternatives presented, and failure to assess RECLAIM in connection with the NOx reduction needs to be covered in the 2016 AQMP and beyond. We will discuss the project objectives and the ensuing flaws in turn. 7-3

Project Objectives

The PEA lists these project objectives: 7-4

1) Comply with the requirements in Health and Safety Code (HSC) §§40440 and 39616 by conducting a BARCT assessment of the NOx RECLAIM program and reducing the amount of available NOx RTCs to reflect emission reductions equivalent to implementing available BARCT;

2) Modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment;

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3) Ensure that RECLAIM facilities, in aggregate, achieve the same emission reductions that would have occurred under a command-and-control approach;

4) Achieve the proposed NOx emission reduction commitments in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM; and, 7-4 Con't

5) Achieve NOx emission reductions to assist in attaining the NAAQS. PEA 2-4.

However, the discussion in the PEA, particularly with respect to alternatives, seems to ignore objectives 3 and 5 by tinkering with the existing RECLAIM rules rather than asking whether the rules serve the purposes of RECLAIM and its governing statute. If the scope of the PEA truly matched up with the project objectives, the errors that we discuss below would not have occurred.

Ending RECLAIM

The goal of RECLAIM is to reduce NOx emissions as efficiently and quickly as possible; this is recognized in project objective no. 3. Although emissions have dropped, it is not at all clear that this has been because of or in spite of RECLAIM. The over-allocation of RECLAIM credits has depressed their price and diminished the economic drivers to reduce actual emissions. When staff completed its most recent BARCT analysis, it became clear that there are too many cheap credits in the market and that a deep "shave" is required. The PEA should take this finding to its logical conclusion and examine whether RECLAIM can, in fact, provide the same emissions reductions as would be achieved under a command and control system. 7-5

Failure to Choose the Environmentally Superior Alternative

The PEA states that Alternative 2, most stringent shave, is the environmentally superior alternative in that it will lead to the greatest NOx reductions. PEA at 5-43. But the PEA rejects Alternative 2 on the basis that it does not "satisfy Objective No. 2 "to modify the RTC "shaving" methodology to implement the emission reductions per the BARCT assessment."" PEA at 5-44. In addition, the PEA states: "the proposed project is considered to provide the best balance between emission reductions and the adverse environmental impacts due to construction and operation activities while meeting the objectives of the project." *Id.* 7-6

This only makes sense if a very strained view of the objectives of RECLAIM is adopted and objectives and project objectives 3 and 5 are ignored. The construction and operational impacts from maximizing the "shave" are tiny in comparison to the benefits to be obtained. It seems more likely that the rejection of Alternative 2 is the result of a political calculation of how strongly the regulated community will complain.

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NOx Reductions and the Ozone NAAQS

South Coast has not met the 1979 1-hour ozone standard, the 1997 8-hour ozone standard, nor the 2008 8-hour ozone standard, and will continue to be hard pressed as it seeks to meet the just-announced 70 ppb standard. The PEA needs to evaluate RECLAIM against the statutory background of the Clean Air Act and the NAAQS ozone limits, as recognized in project objective no. 5, but has not done so in a meaningful way. 7-7

Thank you for your consideration of this letter.

Yours truly,

David Pettit
Staff Attorney
Natural Resources Defense Council

Evan Gillespie
Deputy Director, Beyond Coal Campaign
Sierra Club

Angela Johnson Meszaros
Staff Attorney
Earthjustice

Shana Lazerow
Staff Attorney
Communities for a Better Environment

RESPONSES TO COMMENT LETTER #7
(Natural Resources Defense Council et al. – October 6, 2015)

7-1 This comment introduces the parties represented by the letter. No response is necessary.

7-2 This comment asserts that RECLAIM has not proven its value as a cheaper or more efficient way to reduce NOx than command-and-control and needs to be substantially strengthened. Staff analysis indicates that RECLAIM has saved facilities substantial sums of money; however, the 2005 shave has not resulted in facilities actually achieving 2005 BARCT levels of emissions. For that reason, SCAQMD staff proposes to substantially strengthen the program by shaving enough RTCs to result in actually achieving 2015 BARCT levels of emissions.

7-3 With regard to the comment about not analyzing an end to the RECLAIM program as a project alternative in the PEA, two opportunities (e.g., during the 57-day public review and comment period of the NOP/IS and at the CEQA scoping meeting) were provided to commenters to suggest ways of crafting the various alternatives to be analyzed in the PEA. The SCAQMD received several suggestions for alternatives to be analyzed, but none of the suggestions requested an alternative that contemplates ending the entire RECLAIM program. For this reason, an alternative contemplating the end of the RECLAIM program was not included in the Draft PEA.

Further, it is important to keep in mind that ending the RECLAIM program would require rescission of all of the rules that comprise Regulation XX, at least to the extent that they would apply to NOx. Proposing to rescind Regulation XX as an alternative would go way beyond the scope of the current project, which is limited to the NOx RECLAIM program and its affected sources. Further, doing so would be an entirely different project that would require its own rule language, stakeholder meetings, public workshops, CEQA analysis, socioeconomic analysis, et cetera. Finally, the concept of ending the RECLAIM program would not qualify as a reasonable alternative to the project because it would not be able to feasibly attain most of the basic objectives of the project while avoiding or substantially lessening any of the significant effects of the project as is required by CEQA Guidelines §15126.6 because one of the basic objectives of the project was to modify RECLAIM by reducing available NOx RTCs to reflect emission reductions equivalent to implementing BARCT. However, to the extent an alternative of ending the RECLAIM program was analyzed, it would have to require implementation of BARCT for the RECLAIM sources, as required by Health and Safety Code §§40440 and 40919. As a result, the environmental impacts of such an alternative would likely be similar to those of the proposed project since they would require similar emission reductions, and thus, would not eliminate or reduce any of the significant adverse environmental impacts of the project.

With regard to the comment about failing to choose the environmentally superior alternative in the PEA, see Response 7-6. With regard to the comment about the project objectives, see Response 7-4.

Finally, with regard to the comment about failing to assess RECLAIM in connection with the NOx reduction needs to be covered in the 2016 AQMP, as explained in Response 6-3, the 2016 AQMP is currently under development and on a completely separate schedule from the proposed project. Staff is fully aware of the needs to get additional NOx reductions from all sources in order to meet the future air quality standards for both ozone and particulates. The proposed RECLAIM amendments attempt to reduce NOx commensurate with BARCT levels for facilities in the NOx RECLAIM program, which will contribute towards air quality goals. As the 2016 AQMP development process moves forward, a separate CEQA analysis of the effects of what is proposed for the 2016 AQMP will be conducted and presented as part of a Program EIR which will provide multiple opportunities for review and comment by the public, stakeholders, and other interested parties.

7-4 Because this comment is vague and omits the basis for the unsubstantiated opinion that the alternatives analysis ignores project objectives #3 and #5, the scope of the project does not match with project objectives, and these factors caused errors in the PEA, SCAQMD staff is unable to provide a detailed response. All the alternatives except Alternative 3 (the Industry Approach) and the Alternative 4 (the No Project alternative) result in a shave that is equivalent to BARCT-level reductions in the aggregate. Therefore, they implement project objective #3, which is to ensure aggregate emission reductions equivalent to what would have occurred under command-and-control. The comment does not identify any additional reductions, beyond BARCT, that could be added to the proposed reductions to assist in attaining the NAAQS, which is project objective #5 per the comment.

7-5 The emission reductions that have occurred since the last BARCT adjustment for RECLAIM facilities in 2005, in aggregate, can be attributed to several factors. From 2007 to 2012, NOx emissions were reduced due to impacts from the economic recession which caused reduced production and facility shutdowns as well as from the installation of some control equipment. The purpose of these currently proposed rule amendments are to further reduce RECLAIM emissions based on BARCT.

As explained in Response 6-6, the data review conducted during rule development as part of the BARCT equivalency demonstration concluded that past NOx RTC shaves were ineffective at reducing emissions to a level that would have occurred under a command-and-control approach. As such, this data review comprised one factor of demonstrating the need for the proposed project (e.g., the need for the NOx RTC shave). For that reason, SCAQMD staff believes that the proposed shave must reduce a significant amount of excess unused RTCs, and the staff proposal does so. The PEA analyzes the environmental effects of implementing the proposed project, and in particular, the environmental effects of providing the same emission reductions as would be achieved under a command-and-control system. The purpose of CEQA is to analyze the adverse environmental effects of a proposed project, identify significant adverse impacts, and adopt feasible mitigation or alternatives to mitigate or avoid those impacts, (Public Resources Code §21002.1) and the PEA has done so. The PEA analyzed a reasonable range of alternatives. Therefore, whether another project (command-and-control rules) would be preferable is not within the required scope of this CEQA analysis. See also Response 7-3.

7-6 The analysis of Alternative 2 concluded that because it may achieve the greatest emission reductions, Alternative 2 qualified as the environmentally superior alternative. However, the goal of project objective #3 is to ensure that the affected RECLAIM facilities would be subject to the same reductions that would otherwise occur under command-and-control and the goal of project objective #5 is to achieve NOx emission reductions to assist in attaining the NAAQS. Contrary to the comment, all of the project objectives were carefully considered in the overall evaluation of Alternative 2, as well as the other alternatives.

Specifically, for facilities with types of equipment and source categories for which no new BARCT (not cost-effective and/or infeasible) was identified and cannot reduce emissions further would not be subject to the RTC shave under the proposed project, but would be shaved under Alternative 2. The proposed project satisfies all of the project objectives but Alternative 2 does not satisfy project objective #3 because staff estimated that it would force many of the 219 facilities to buy more RTCs in order to achieve compliance (see Draft Final Socioeconomic Report, Section 9) while under a command-and-control regime and under the proposed project, these same facilities would not have to make any additional changes to achieve more NOx emission reductions. Because of this disparity that would apply to a disproportionately large number of RECLAIM facilities, the alternatives analysis concluded that the proposed project is preferred over Alternative 2 as well as the other alternatives.

7-7 The comment states that the PEA has not evaluated RECLAIM against the statutory background of the Clean Air Act and the NAAQS ozone limits, but project objective #5 was carefully considered in drafting the SCAQMD staff's proposal. The commenter has not identified any additional emission reductions beyond BARCT-level reductions that are feasible for the RECLAIM universe.

The purpose of project objective #5 is to ensure that the proposed project achieves NOx reductions to <u>assist</u> with achieving attainment the National Ambient Air Quality Standards (NAAQS). However, project objective #5 is not to be achieved in conflict with project objective #3, which is to ensure BARCT emission reductions are commensurate with command-and-control. SCAQMD staff has conducted a BARCT analysis and believes that a 14 ton per day reduction will result in the necessary, actual BARCT reductions required by the analysis. If the proposed project is adopted by the SCAQMD Governing Board, the NOx emission reductions will be accounted for in the overall attainment demonstration as part of the ongoing development of the 2016 AQMP, which is a comprehensive and integrated Plan primarily focused on addressing the ozone and PM2.5 standards. As with every AQMP, a comprehensive analysis of emissions, meteorology, atmospheric chemistry, regional growth projections, and the impact of existing control measures and the corresponding rules or rule amendments, is updated with the latest data and methods. The result is a targeted level of emissions in the Basin that would allow attainment of the NAAQS. The 2016 AQMP will incorporate the latest scientific and technical information and planning assumptions, including the latest applicable growth assumptions, Regional Transportation Plan/Sustainable Communities Strategy, and updated emission inventory methodologies for various source categories.

Comment Letter #8

COMMUNITIES FOR A BETTER ENVIRONMENT

October 6, 2015
Barbara Radlein
South Coast Air Quality Management District
bradlein@aqmd.gov.

Re: Comments on SCAQMD Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Dear Ms. Radlein,

Thanks for your work on this important issue. We submit the following comments regarding the Draft Program Environmental Assessment (PEA) for the Proposed Amended RECLAIM regulations,[1] in addition to the comments submitted today by Natural Resource Defense Council and Sierra Club. Additional reductions beyond those proposed in the PEA are readily achievable, cost-effective, and necessary, given the severe impacts on health of these air pollution sources in the South Coast. Incorporating these additional reductions into Regulation XX would "reduce the allowable NOx emission limits based on current Best Available Retrofit Control Technology (BARCT) to achieve additional NOx emission reductions," and must be included in any rule purporting to reflect BARCT for refinery boilers and heaters. The PEA must be recirculated, and must include a preferred alternative that, at a minimum, reflects these reductions. 8-1

Additional reductions are readily achievable from Refinery Boilers and Heaters

The proposed Draft PEA NOx reductions for Refinery Boilers and Heaters in the South Coast is 0.96 tons per day (tpd), using the addition of SCR (Selective Catalytic Reduction).[2] There is substantial evidence that much higher reductions could be achieved. In 2010, CBE evaluated data provided by the California Air Resources Board (CARB) on Refinery Boilers and Heaters.[3] CARB listed many additional control options for improving the efficiency of Boilers and Heaters 8-2

[1]Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), August 2015, SCAQMD No. 12052014BAR, State Clearinghouse No: 2014121018, Author Barbara Radlein, **hereafter the DRAFT PEA**, available at: https://mail.google.com/mail/u/0/#advanced-search/subset=inbox&has=RECLAIM&within=1d&sizeoperator=s_sl&sizeunit=s_smb/14ffcf615d913d4d?projector=1
[2]*Id.* at p. 1-26.
[3] The CARB Boiler and Heater data was downloaded from http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm at the bottom of the page, "Supplemental Material," Compliance Pathways Analysis – Boilers, and Compliance Pathways Analysis—Heaters.

statewide. CARB focused on greenhouse gas emissions reductions, but because these control options save fuel, they also substantially reduce emissions of co-pollutants, including NOx.

The measures identified are an indication that there is a much higher potential to reduce NOx from Refinery Boilers and Heaters, beyond SCR controls. The CARB data identified many measures to improve the efficiency of the fleet of refinery boilers and heaters, ranging from simply stopping leaks and improving insulation, to completely replacing old boilers. These measures were found not only to be cost-effective, but to actually *save* money for oil refineries. The RECLAIM PEA, by contrast, did not provide such a wholesale evaluation of clean-up measures for Boilers and Heaters.

CBE took the CARB data (which provided fuel use, GHG emissions, and cost of various measures), and calculated tables showing NOx co-pollutant reductions that would be associated with these GHG reductions and fuel use reductions.[4] CBE reported these in the December 14, 2010 comments to CARB (pages 27-30, in the NOx tables), which are attached. We are also attaching the original CARB spreadsheets, which have CBE's calculations added. 8-2 Con't

These resulted in 15.08 tpd in NOx reductions from Refinery Boilers (16.44 for all Boilers sources) and 7.1 tpd for Refinery Heaters (7.35 tpd for all sources), for a total of 22.18 tpd statewide for refineries (and 23.79 for all sources). Oil refineries within the South Coast make up about 54% of the state's refining capacity,[5] and 54% of 22 tpd from the statewide oil refinery Boiler and Heater NOx reduction opportunities would result in about 12 tpd in NOx reductions, far above the .96 tons per day proposed. These do not include the other sources listed by CARB (non-refinery Industrial Boilers and Heaters). This data provides substantial evidence that much higher reductions could be achieved from this one source.

The PEA should therefore be revised to provide a more refined and updated analysis specific to the South Coast data. SCAQMD should re-circulate this revised PEA, providing a detailed alternative evaluation of NOx reductions achievable through the measures identified by CARB, including:

1. Replacing low and medium efficiency Boilers
2. Optimizing Boilers by reducing excess air
3. Retrofitting Feedwater Economizers
4. Retrofitting with Air Preheaters
5. Blowdown Reduction With Controls and with Feedwater Cleanup 8-3
6. Blowdown Heat Recovery
7. Optimizing Steam Quality
8. Optimizing Condensate Recovery
9. Minimizing Vented Steam
10. Insulation Maintenance
11. Steam Trap Maintenance
12. Steam Leak Maintenance

[4] For this calculation, CBE applied standard AP-42 Boiler and Heater NOx emissions factors.
[5] CA.gov Energy Almanac, listing capacity of each California refineries, November 2014, http://energyalmanac.ca.gov/petroleum/refineries.html http://energyalmanac.ca.gov/petroleum/refineries.html

2

13. Replacing Low and Medium Efficiency Heaters
14. Optimizing Heaters
15. Recovering Flue Gas Heat
16. Replacing Refractory Brick
17. Insulation Maintenance

8-3 Con't

These reduction measures in total would also achieve about 4 million tonnes CO_2 equivalent/year, and save about $46 million dollars, as determined by the CARB data. CBE has noted that despite the savings that oil refineries could achieve from cleaning up old boilers and heaters, they frequently put off doing so until they can use the reductions as offsets for other refinery expansions planned, leaving boilers and heaters to go on unnecessarily polluting for decades. We urge the AQMD to provide the public with a detailed analysis of the additional reductions that could be achieved through *requiring* such measures.

Sincerely,

Shana Lazerow, Staff Attorney

Julia May, CBE Senior Scientist

Attachments

3

Communities For A
Better
Environment

December 14, 2010

Mary Nichols, Chairman
James Goldstene, Executive Officer
California Air Resources Board
1001 "I" Street
P.O. Box 2815
Sacramento, CA 95812
Via email: mnichols@arb.ca.gov, jgoldstene@arb.ca.gov

Re: CBE Comments on Draft Cap and Trade Regulation: Draft Cap & Trade Regulation Misses California GHG and Pollution Reduction Opportunities, Job Opportunities, and Contains Egregious Errors

Dear Chairman Nichols and Mr. Goldstene,

In our October and December 2008 comments on ARB's Scoping Plan, Communities for a Better Environment raised numerous substantial concerns and described the significant pitfalls of cap and trade schemes. We specifically described why cap and trade programs do not work to significantly reduce greenhouse gas emissions and how they harm low-income communities and communities of color. ARB did not respond to these concerns. Indeed the proposed regulation would animate some of CBE's greatest fears.

Overwhelmingly, cap and trade programs suffer from credit overallocation, monitoring and equivalency problems, loss of innovation, unverifiability of offsets, unverifiable accounting practices, and lack of additionality. Cap and trade schemes also exacerbate environmental injustice by increasing hotspots, creating price volatility, and leading to oppression through high risk and fraudulent offset projects that too often also result in displacement. The proposed regulation does nothing to avoid the known pitfalls inherent to cap and trade.[1] Instead, the regulations bend over backwards to accommodate polluters' desire for zero cost compliance, ease and flexibility at the expense of true significant reductions, health protection (avoiding increases in other pollution), and environmental justice. It also used a flawed calculation of emissions as the foundation for

[1] For more information on these issues, please see further exploration and elaboration in comments written by the Center on Race, Poverty & the Environment and cosigned by CBE.

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all of its estimates. Throughout its pages, the proposed regulation violates the letter and spirit of AB32.

AB32 specifically requires that ARB "ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities."[2] The regulations may not "interfere with efforts to achieve and maintain federal and state ambient air quality standards to reduce toxic air contaminants,"[3] must minimize leakage,[4] "consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, the environment and public health",[5] and "consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases[6]. But if ARB adopts a cap and trade program, AB32 additionally requires ARB to affirmatively "design" the program "to prevent any increase in emissions of toxic air contaminants or criteria pollutants,"[7] consider direct, indirect and cumulative emission impacts from the program, and direct private and public funds to disadvantaged communities.[8] The proposed regulations overwhelmingly ignore these requirements, and ARB's failure to analyze reasonable alternatives makes adoption of the draft regulations even more irrational.

The comments below find:

- **Industrial GHG emission sources are massive** (largely oil industry emissions), but still underestimated in CARB documents
- **Despite the volume and toxicity of industrial co-pollutants (especially oil industry), there are zero tonnes of direct controls required for this source** – all are allowed to be completed through buying pollution credits from outside any particular industry, and carried out outside California or the U.S.
- **Furthermore, industrial sources are not required even to buy credits under the proposal** – they are 100% free.
- **Large California NOx, CO, and other co-pollutant reductions can be achieved if an alternative is adopted requiring direct control measures**[9]

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[2] H&S Code § 38562(b)(2).
[3] H&S Code § 38562(b)(4).

[5] H&S Code § 38562(b)(6).
[6] H&S Code § 38562(b)(9).
[7] H&S Code § 38570(b)(2).
[8] H&S Code § 38565.
[9] Termed by CARB as measures "complementary" to Cap and Trade, and agreed by CARB and other agencies to be key for overall success of the program.

using methods known by CARB (e.g. for boilers and heaters). These co-pollutants otherwise cause large cumulative impacts in communities of color. Similarly CARB should evaluate other co-pollutants including pm2.5 and toxics which feasible direct controls would achieve. AB32 requires addressing the co-pollutants issues, but the proposed Cap and Trade regulation and Scoping Plan do not.

- **Such project alternatives just described would create California jobs, California health improvements**, and the best model for regions outside California to replicate. They were not considered. Cost effectiveness calculation of such controls should include the benefits of reducing GHGs, reducing smog and toxics, and reducing health impacts.
- **The current project not only misses these opportunities, but allows harms to California,** for instance, by allowing increasing industrial pollution in heavily industrialized California communities, and by causing evictions of indigenous people through fake forest offset projects.
- **Outright exemption from regulation is provided for large portions of oil refinery sources,** which must also be removed (see below).
- Available measures for industrial sources that should be added, include:
    - Implementing **industrial boiler and heater replacement** listed by CARB in the published spreadsheets
    - **Removing methane exemptions** present in California smog regulations, which will reduce both GHGs and regional smog co-pollutants.
    - Requiring implementation of specific refinery by refinery measures identified in the **industrial energy efficiency audits**
    - **Limits on the use of dirty crude oil,** which is similar to what the electric power industry must meet.
    - **A thorough evaluation of Reasonably Available Control Measures** at oil refineries and industrial sources, minimizing both GHGs and co-pollutants
    - Additional measures discussed in this document

- **CARB originally considered direct control of oil refinery reduction measures and found them feasible,** but later lumped oil refineries and industrial sources in with all other Cap and Trade sources, despite findings that direct controls were

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feasible. If CARB made these fixes for industrial sources and as well for other sources causing health impacts in California (such as agricultural and electrical sources), the severe impacts caused by Cap and Trade, and the ineffectiveness of it, would be greatly lessened.

- **CARB must include a strategy to implement the requirement to direct monetary benefits to disadvantaged communities.**

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Overview of Cap & Trade harms:

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I. Cap & Trade Industrial GHG reductions are tiny & can be beefed up; if instead achieved in-state, they would generate local jobs, health benefits, and be verifiable

A. Industrial emissions, especially oil industry, are big but underestimated

The success of cap and trade programs is dependent on identifying the correct number of reductions needed, requiring those reductions, and setting a low enough cap, but CARB systemically miscalculates industrial emissions, making it difficult or impossible to verify reductions in comparison to the targets and initial allocations.

Moreover, AB32 requires ARB to adopt regulations to achieve the maximum technologically feasible GHG reductions from sources and categories of sources.[10] Here, GHG industrial sources are very large, but reductions in the proposed Cap and Trade plan, especially for oil refineries, are miniscule, despite many available options for reductions. Total emissions from the capped portion of this sector were found by CARB at 75.69 million metric tonnes CO2 equivalent (or MM tonnes CO2e) in 2008. An excerpt from CARB's document *2020_ghg_emissions_forecast_2010-10-28* (attached), last updated 10/28/2010 shows the large contribution of different industrial subsectors to California (shown projected without Scoping Plan reductions):**[11]**

Category	2008	2009	2010	2011	2012
Grand Total	**474.64**	**457.65**	**462.04**	**463.23**	**470.37**
Industrial (Capped)	*75.69*	*74.15*	*73.26*	*73.42*	*73.66*
Cement Plants	8.64	8.64	8.64	8.64	8.64
Cogeneration Facilities	11.13	10.37	10.02	9.87	9.81
Hydrogen Plants	2.22	2.20	2.18	2.18	2.18
Petroleum Refining	34.58	34.24	33.89	33.89	33.87
Other	0.21	0.20	0.20	0.21	0.22
General Stationary Combustion	18.91	18.50	18.32	18.63	18.94

2013	2014	2015	2016	2017	2018	2019	2020
480.40	**487.35**	**492.01**	**494.66**	**497.88**	**500.76**	**503.76**	**506.78**

[10] H&S Code §38560.

[11] *California GHG Emissions - Forecast (2008-2020)*, 10/28/2010, 2020_ghg_emissions_forecast_2010-10-28, http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf

74.03	***74.10***	***74.12***	***74.17***	***74.20***	***74.20***	***74.21***	***74.21***
8.64	8.64	8.63	8.63	8.63	8.63	8.63	8.63
10.08	10.27	10.46	10.65	10.83	11.01	11.19	11.38
2.18	2.18	2.17	2.17	2.17	2.17	2.17	2.17
33.85	33.82	33.80	33.77	33.75	33.72	33.69	33.66
0.23	0.23	0.23	0.24	0.24	0.24	0.25	0.25
19.06	18.97	18.83	18.70	18.57	18.43	18.28	18.13

The table shows industrial emissions at about 74 MM tonnes CO2e from 2008 to 2020. Oil refineries, the largest industrial subsector, is shown at about 34 MM tonnes CO2e over this period. The whole industrial sector in fact is even larger when uncapped industrial sources are included. Another CARB chart (*Gross emissions and sinks* excerpted below) provides the total for all industrial sources at about 100 MM tonnes CO2e.

Oil industry sources are even bigger than they appear, because the listings split them into separate categories, with some categories not clearly labeled. Oil refineries should be added to Hydrogen Plants (which produce hydrogen at oil refineries for oil refinery use, by burning fossil fuels), and added to a large portion of the Cogeneration total, since large numbers of cogeneration comes from oil refinery sources.

It appears that another hidden oil industry source is also contained under the label “General Stationary Combustion.” This can be determined by reviewing the CARB table below. “Oil & Gas Extraction” at 17.04 MM apparently makes up most of the 18.91 MM tones of “General Stationary Combustion.” Because the oil industry is not only a major contributor to GHGs and toxics, the breadth of the oil industry sources should be made clear in the inventories.

California Greenhouse Gas Inventory for 2000-2008 — Summary by Economic Sector[12]

[12] http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_sector_00-08_sum_2010-05-12.pdf

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Gross emissions & sinks	2008
Industrial	**100.03**
CHP: Industrial	10.47
Landfills	6.71
Manufacturing	22.47
Mining	0.19
Not Specified Industrial	2.24
Oil & Gas Extraction	17.04
Petroleum Marketing	0.00
Petroleum Refining	35.60
Pipelines	2.62
Wastewater Treatment	2.70

This puts the oil industry sources in the CARB documents at:

Oil refineries 34 MM tonnes
\+ Hydrogen plants about 2MM tonnes
\+ Oil and gas extraction at 17 MM tonnes
\+ Cogeneration -- some large portion of 11 MM tonnes

= about 55 to 60 MM tonnes from the oil industry,
currently required to achieve zero direct emission reductions

Even this large sum of emissions is an underestimation.

Hydrogen Plant emissions are underestimated:

For example, hydrogen plants at oil refineries are growing at a fast rate, in order to allow refineries to process heavier, more contaminated crude oil. Just one hydrogen plant can emit over a million tonnes per year of CO2e (such as at the ConocoPhillips Rodeo facility[13]), so it is almost certain that the total of 2.22 MM tonnes listed for hydrogen plants now is actually much higher and getting even bigger than listed in the CARB chart.

CBE has previously provided a partial list of additional hydrogen plant projects in comments to CARB, and we incorporate those by reference. CBE also previously requested that CARB perform a more detailed assessment of planned hydrogen plants expansions at refineries, and we included the following chart in both written comments

[13] Excerpt of ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project, Final Environmental Impact Report, Volume 1 – Response to Comments, cover and table of GHG emissions, Attachment CBE 1 - ConocoPhillips Rodeo H2 Plant GHGs

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submitted,[14] and in testimony at a CARB hearing. This chart shows that just due to new hydrogen plants added, or in the process of being built, in the last decade, about 6 million tonnes per year of CO2 emissions were added.. This is a continuing trend that needs to be reigned in; it is caused by huge GHG increases that appear not to be accounted for by CARB, as well as by big local pollution increases during these oil refinery expansions that are occurring for the purpose of switching to heavier, more contaminated, cheaper crude feedstocks at oil refineries.

Examples of CA Refinery Hydrogen Plant Expansions (not comprehensive) (million standard cubic feet)	**Approximate CO2 Emissions** (metric tonnes /yr)
2007 ConocoPhillips Rodeo --120 MMscf	at least 1,250,000
2007 Chevron Richmond -- 100 MMscf	at least 900,000
2007 Valero Benicia – unknown MMscf	≈ 860,000
2003 Chevron El Segundo -- 90MMscf	≈ 940,000
1999 Air Products Wilmington for area refineries -- 96 MMscf	≈ 1,000,000
1996 Air Products for Ultramar, Wilmington --83 MMscf	≈ 860,000
493 MMscf (million standard cubic feet)	**Almost 6 million metric tons per year**

Furthermore, GHGs from oil refineries overall are getting worse due to switches to dirtier crude oil, running counter to other industries (such as electric power plants), which are switching to lighter feedstocks. The recent peer-reviewed study published by CBE Senior Scientist Greg Karras in the journal Environmental Science and Technology[15] found that very large increases in GHG emissions are occurring due to the switching to dirtier crude oil at oil refineries, underlining the importance of accurate inventories and

[14] Attachment C -- Comments on CARB AB32 Scoping Plan, Oil Refineries, by CBE (part of a 3-part comment by EJ groups, previously submitted to CARB, May 2008, attached, Attachment CBE 2 – Previous CBE Comments May 2008

[15] *Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential?*, *Environ. Sci. Technol.*, 2010, *44* (24), pp 9584–9589, DOI: 10.1021/es1019965, November 30, 2010, Copyright © 2010 American Chemical Society http://pubs.acs.org/doi/abs/10.1021/es1019965, Attachment CBE 3 – GKarras Environ Sci Technol paper High GHGs Dirty Crude

forecasts, and controls and limits addressing this switch. While CBE has testified on this issue to CARB for a number of years, and CARB is well aware of this general trend, the new study provides a detailed evaluation of data nationally, which shows in detail how sharp this increase is. The paper found: *"Fuel combustion increments observed predict that a switch to heavy oil and tar sands could double or triple refinery emissions and add 1.6−3.7 gigatons of carbon dioxide to the atmosphere annually from fuel combustion to process the oil."* We urge CARB to review the attached publication, and to address this issue.

Pressure for growth in polluting oil refinery cogeneration of electricity

In addition,oil refineries have pushed for subsidized cogeneration, a truly bad idea, which would replace clean energy electricity, with oil refinery-generated electricity. While industrial energy efficiency is essential, and while existing refinery processes should be required to capture waste heat, adding unneeded, expanding oil refinery electricity is directly counter to the RPS (Renewable Portfolio Standard), which is aiming at converting fossil fueled electricity into clean electricity. **CARB must not allow oil refinery-generated electricity to subvert this process and take us backwards.**

Large portions of refineries have been removed from regulation by redefining them as non-refineries

Even the seemingly straightforward category of "oil refineries" is being parsed into bits, with oil refineries that process intermediate materials being exempted, and even removed from the definition of oil refineries in the regulation, despite the fact that they are inherently part of an oil refining company's overall production process. It is unclear whether the re-defined refinery portions are included in the capped emission estimation of 34 MM tonnes or not, but it is clear they are exempted from the caps. This approach undermines the requirement to adopt regulations that achieve technologically feasible GHG reductions from sources and categories of sources because it allows large unregulated oil refining emissions.[16] The proposed Cap and Trade oil regulation definition states:

> *"Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through re-distillation, cracking, or reforming of unfinished petroleum*

[16] H&S Code § 38560.

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> *derivatives. **Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.***[17]

Recommendation: **The last sentence in the regulation definition should be struck,** as this definitional difference has no relation in determining whether such facilities emit large amounts of GHGs, criteria pollutants, or toxics. CARB should use standard industrial classification codes for oil refineries used by EPA and remove baseless exemptions, to prevent large unregulated oil refining emissions.

CARB provided no evaluation of the environmental impacts caused by exempting these sources. This definition is another means by which the oil industry has received special unnecessary exemptions from regulation under the Scoping Plan and its implementation. Many individual oil refining companies own geographically separated facilities that nevertheless are operated together as an integrated refining operation whether or not one portion treats intermediate materials. Regional smog regulators routinely treat these facilities as one facility, and would never consider exempting them from regulatory standards, such as Clean Air Act requirements, based on whether they process "transmix" materials, rather than based on their actual air emissions and impact on the environment. For greenhouse gas purposes, there is similarly no justification for treating some refinery facilities as exempt without at least providing an emission threshold above which they are subject to regulation. Other entities must abide by simple emission thresholds (>25,000 metric tonnes), so this exemption also represents an unfair business practice, with oil refineries getting a sweetheart deal.

B. Oil industry reductions are small or non-existent

The industrial sector has zero tonnes of specific reduction requirements, as provided by CARB in the chart below, including for the largest sources, the oil industry. This most polluting industrial sector has been successful in winning the complete abandonment in control requirements, a fact which is nothing less than shameful for our State. AB32 requires ARB to consider the significance of the contribution of each source or category of sources(in adopting a regulation).[18] There is no way this can be argued as

[17] Regulation Definitions, page A-28 , http://www.arb.ca.gov/regact/2010/capandtrade10/capv1appa.pdf
[18] H&S Code §38562(b)(9).

meeting AB32's requirement to maximize reductions, and to reduce co-pollutants.[19] CBE urges CARB to correct this egregious error.

Greenhouse gas Reductions from Ongoing, Adopted and Foreseeable Scoping Plan Measures[20]

Million tonnes of CO2 equivalent

Total of All Measures	**62.0**
Measures in Capped Sectors	**49.0**
Transportation	***24.4***
T-1 Advanced Clean Cars	3.8
T-2 Low Carbon Fuel Standard	15.0
T-3 Regional Targets (SB375)	3.0
T-4 Tire Pressure Program	0.6
T-5 Ship Electrification	0.2
T-7 Heavy Duty Aerodynamics	0.9
T-8 Meadium/Heavy Hybridization	0.0
T-9 High Speed Rail	1.0
Electricity and Natural Gas	***24.6***
E-1 Energy Efficiency and Conservation	7.8
CR-1 Energy Efficiency and Conservation	4.1
CR-2 Solar Hot Water (AB 1470)	0.1
E-3 Renewable Electricity Standard (20%-33%)	11.4
E-4 Million Solar Roofs	1.1
Industry	
I-1 Energy Efficiency and Co-Benefits Audits for Large Industrial Sources	0.0
Measures in Uncapped Sources/Sectors	**12.9**
H-1 Motor Vehicle A/C Refrigerant Emissions	0.2
H-2 SF6 Limits on non-utility and non-semiconductor applications	-
H-3 Reduce Perfluorocarbons in Semiconductor Manufacturing	0.2
H-4 Limit High GWP use in Consumer Products	0.2
H-6 Refrigerant Tracking/Reporting/Repair Deposit Program	5.8
H-6 SF6 Leak Reduction and Recycling in Electrical Applications	0.1
F-1 Sustainable Forests	5.0
RW-1 Landfill Methane Control Measure	1.5

Last Updated: 10/28/2010

According to CARB's regulation notice document, the entire Cap and Trade regulation will get 18 to 27 MMTCO2e reduction by 2020, but none of these reductions are required to be achieved by oil refineries.[21] The regulation and staff report documents make it clear that no entity is required to reduce emissions at their site.

[19] H&S Code §§ 38560, 38562(b)(6), 38570(b)(2).

[20] CARB, reproduced above and available at: http://www.arb.ca.gov/cc/inventory/data/tables/reductions_from_scoping_plan_measures_2010-10-28.pdf

[21] "Staff estimates that implementation of the proposed regulation would reduce GHG emissions by 18 to 27 MMTCO2e in 2020." *Notice of Public Hearing to Consider the Adoption of a Proposed California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms Regulation, including Compliance Offset Protocols,* http://www.arb.ca.gov/regact/2010/capandtrade10/capnotice.pdf

A highly preferable alternative proposal would have been a thorough evaluation of Reasonably Available Control Measures necessary to meet CARB's requirements under AB32 for maximum reductions, to reduce smog in non-attainment zones, and toxics in overburdened heavily industrial areas. The following sections identify specific sources that should have been considered. For example, additional reductions could be achieved from:

- Requiring In-State reductions from industrial **boilers and heaters**, which CARB has already identified
- Removing **industrial exemptions for methane** from smog regulations,
- Requiring implementation of specific refinery by refinery measures identified in the **industrial energy efficiency audits**
- Limiting emissions and conversion to processing **Heavier Crude** at oil refineries (which is not cancelled out by adding polluting ethanol to gasoline)
- Requiring oil refineries to **switch fossil fuel electricity** use to clean alternative energy sources (since oil refineries use significant electricity)

More detail is provided below. CARB also found during the Scoping Plan process that many of these refinery control measures are feasible, but never required that these be carried out.

C. Boiler and Heater NOx and CO Co-pollutant emissions are large and if directly controlled would yield large local health benefits

AB32 requires ARB to design the program to *prevent* any increase in emissions of toxic air contaminants or criteria pollutants.[22] It also requires it to consider the overall societal benefits of reducing other air pollutants and benefits to the environment and public health.[23] Yet the draft regulation demonstrates that reductions could have been achieved to substantially reduce co-pollutant emissions but was rejected.

CARB provided two spreadsheets calculating available measures for reducing CO2 emissions from industrial boilers and heaters, which are major pollution sources.[24] Measures include replacing old boilers of low or medium

[22] H&S Code § 38570(b)(2).

[23] H&S Code § 38562(b)(6).

[24] Compliance Pathways Analysis – Boilers, available at http://www.arb.ca.gov/cc/capandtrade/capandtrade/compathboiler.xls and Compliance Pathways Analysis -

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efficiency, optimizing combustion, improving insulation maintenance, etc. (listed below and in the attached spreadsheets). CARB identified how much energy would be saved for each of these measures in MMBTU (million British Thermal Units). CARB provided these reduction opportunity calculations not because these are being directly mandated, but to show possible ways that industrial sources *could* reduce, but are nevertheless allowed to buy their way out of under Cap and Trade. There was no showing that these reductions would not have been cost-effective. Regardless, the CARB list underscores the availability of measures for direct control. If these controls were implemented locally instead of traded, they would not only result in the CO2 emissions reductions identified by CARB, but would also result in very substantial co-pollutant reductions. **CARB should have considered such an alternative project to address co-pollutant impacts.**

It is a simple matter to calculate the co-pollutants associated with the energy savings identified in the boiler and heater speadsheets. For example, standard AP42 emission factors for NOx and CO are available, based on natural gas combustion.[25] This will generally underestimate emissions because more polluting fuels are often used by these boilers and heaters, but applying the natural gas factors provides a conservative estimation, and still comes out to large emissions. The result, in tons per day, is provided below. The detailed tables are attached as an appendix. Thethe full spreadsheets are separately attached.

Process Heaters, available at http://www.arb.ca.gov/cc/capandtrade/capandtrade/compathprocessheat.xls , also attached with CBE calculation sheet added to original CARB spreadsheet, Attachment CBE 4 – CBE calcs added to CARB Boiler data, and Attachment CBE 5 – CBE calcs added to CARB Heater data

[25] AP42 Chapter 1.4 provides the emission factors in units of lbs/scf (standard cubic feet of natural gas). Calculating as if all the units used natural gas, which is about 1020 btu/scf, we can convert the emissions factors to lbs NOx and CO per MMBTU. Since CARB provides the MMBTU, our spreadsheet provides the results in lbs NOx and CO. CARB's data was for 2008annual emissions. Converting lbs/year to tons per day (a standard form used to evaluate the significance of criteria pollutants or smog precursors) yields the data provided in the chart below. CBE's spreadsheet, which includes the CARB spreadsheets plus CBE's NOx and CO calculations, is attached., Attachment CBE 6 – AP42 Chapter 1.4

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The results are:

Boiler NOx reductions of 16.44 tpd + **Heater NOx** reductions of 7.35 tpd
= **about 24 tons per day NOx**

Boiler CO reductions of 5.7 tpd + **Heater CO** reductions of 2.47 tpd
= **about 8 tons per day CO**

For comparison, the following South Coast Air Quality Management District's ("SCAQMD") 2007 Clean Air Plan chart[26] shows total NOx for all the region's oil refineries averaged at about 13 tpd and total refinery CO emissions averaged at about 20 tpd:

Total Criteria Emissions South Coast Oil Refinery Emissions Data

(tons per day)	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004	Average of 2001-2002 & 2002-2003 time periods
ROG	8.0	7.7	7.3	8.2	7.9	7.7
NOx	20.1	15.5	13.4	12.8	12.3	13.1
SOx	21.3	19.9	17.2	15.8	14.0	16.5
CO	18.4	14.6	18.2	22.0	21.8	20.1
PM	4.0	4.0	4.0	3.6	3.7	3.8

This demonstrates that NOx and CO reductions achievable statewide from directly controlling industrial boilers and heaters is large, using the methods identified by CARB. Reductions are on a par with the entire NOx and CO refinery emissions in the Los Angeles region. This region is the biggest refining area in the state. The Cap and Trade program on the other hand, allows refineries to buy their way out of achieving these reductions through credits obtained from other states or countries. Since most of these refinery sources are located in heavily industrial area, in communities of color, these sources create cumulative impacts in these areas, and allowing refineries to do buy pollution credits instead of directly controlling these sources, is inconsistent with environmental justice.

D. Methane is exempted from smog regulations, statewide

[26] *Refinery Trends – Criteria Pollutants*, 8/18/05, http://www.aqmd.gov/prdas/refinery/pdf/emission_trend.pdf, attached, Attachment CBE 7 – SCAQMD Refinery Criteria Pollutants

Comments submitted to CARB by CBE in May of 2008 on the Scoping Plan identified, based on CARB data, methane emissions that are exempt from regulation. For example, three categories of Stationary Sources listed (Fuel Combustion, Petroleum Production and Marketing, and Industrial Processes) emitted about 466 tons per day (about 170,000 tons methane per year) of exempt compounds, which is likely to be mostly methane. This is about 4 million tons CO2e per year. There is no reason to continue exempting these emissions, either for smog, or for GHG impacts. Please see the attached comments, page 10.[27] It is now known that methane is a considerable contributor to smog, as also discussed in this earlier comment. AB32 requires the maximum technologically feasible GHG reductions of carbon dioxide, methane, nitrous oxide, hydroflourocarbons, perflurocarbons, and sulfur hexafluoride; carbon is only one GHG.[28] Furthermore, CARB should remove entirely the methane exemptions for all sources in the state, including transportation sources. CBE proposed this, and CARB found it to be a feasible reduction measure, but never implemented it. Now CARB should evaluate adding this measure as a complementary reduction, as an alternative to the current Cap and Trade proposal, in order to achieve the maximum technologically feasible reductions.

E, Needed Co-Pollutant reductions do not address Environmental Justice issues

Any area with one refinery in it is impacted by a major pollution source. One example of extreme Environmental Injustice impacts due to the oil industry, with the very highest concentration of oil refineries in the state, is the Wilmington/Carson area in Southern California which contains about a third the state's refining capacity. This area includes about half of Los Angeles' refining capacity (five refineries and about 650,000 bpd). In the Los Angeles region overall, refineries dominate the top 15 VOC (Volatile Organic Compound) emitters, out of many hundreds of Stationary Sources listed by SCAQMD in the 2007 Air Quality Management Plan. The Wilmington Area includes about half the refinery VOCs emissions[i] (about 1,600 out of 3,200 tons per year) in the LA region. A plume map provided by SCAQMD graphically displays that Wilmington receives the air pollution from five overlapping refining plumes (isopleths) generated over this area (two ConocoPhillips refineries, Valero, BP, and Tesoro):

[27] Ibid, Attachment C -- Comments on CARB AB32 Scoping Plan, Oil Refineries, by CBE (part of a 3-part comment by EJ groups, this portion provided by CBE, attached), May 2008
[28] H&S Code §§ 38505(g), 38560.

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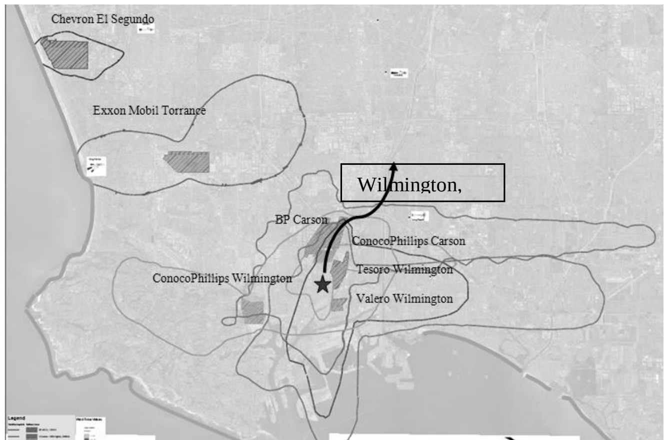

Wilmington has the following demographics, [29] which demonstrate that people of color and low income people are bearing the brunt of the heavy industry concentration in this area.

	Wilmington	**LA**
Hispanic or Latino of any race	85%	45%
Median household income	$30,260	$42,190
Individuals below the poverty level	27%	18%

As if this extreme concentration of oil refineries was not enough to warrant local cleanup efforts, this area also includes oil drilling operations (Wilmington is the third largest oil field in the U.S.), extreme heavy diesel truck traffic (as a major goods movement corridor), the biggest Ports in the Country (Ports of LA and Long Beach which are the biggest single pollution sources in the area), and hundreds of other industrial sources. Clearly, refining areas are in need of direct, local pollution controls, not the potential for further concentration and expansions that the Cap and Trade proposal makes likely, through allowing refineries to buy their way out of local pollution control.

[29] U.S. Census Bureau, Zip Code Tabulation Area 90744, Census 2000 Demographic Profile HIghlights

II. The Cap and Trade regulation can cause Co-Pollutant hotspots, especially due to foregoing reductions of more toxic emitters for more benign ones

Pollution hotspots are areas where pollution concentrates locally rather than dispersing. (Greg Karras, *Flaring hot spots: Assessment of episodic local air pollution associated with oil refinery flaring using sulfur as a tracer* CBE Report (July 2005). Hotspots can have dire health and other quality of life consequences. For instance, modeling has shown that RECLAIM actually increased NO_x concentrations in Wilmington, a low income community of color in Los Angeles, beyond what would have resulted without RECLAIM. (*See* Raul P. Lejano et al, *Testing the assumptions behind emissions trading in non-market goods: the RECLAIM program in Southern California*, ENV'T SCIENCE & POLICY 8 (2005) pp. 371, 374)

Hotspots are an issue in the carbon trading context because carbon dioxide is almost always released with other pollutants, or "co-pollutants. These co-pollutants can include particulate matter including heavy metals, VOCs such as benzene, sulfur compounds, and hundreds of other toxic compounds. If a facility located in an overburdened community "buys" carbon from other facilities so that it can increase its GHG emissions, it is also increasing its emissions of toxic compounds. Said another way, by taking pollution that occurs across a large area and concentrating that pollution in an environmental justice community, the toxic load in that community increases.

In addition, by mixing many different sources together into one big Cap and Trade program, the differences in co-pollutants emitted by different facilities and equipment is lost, and left unaddressed. Consequently an oil refinery CO2 source that happens to have high benzene or high mercury, or high PM2.5 co-pollutants emissions, is treated the same as a food industry source CO2 that burns natural gas, but has low co-pollutant emissions. This allows an oil refinery source to avoid regulation, or even expand, by buying it's way out through clean up of a facility with less toxic co-pollutants. If the oil refinery uses forest credit offsets, it definitely means that a more toxic source (an oil refinery) is offset by a less toxic source.

The proposed regulation does nothing to avoid hotspots or co-pollutant emissions. Yet AB32 requires that,

> "*Prior to the inclusion of any market-based compliance mechanism in the regulations* . . . the state board shall . . . **(**1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution; (2) *Design* any market-based compliance

> mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants."[30]

This failure must be corrected. In fact, ARB failed to take the first step necessary to do the analysis to determine cumulative impacts.

Framework for the Co-Pollutant Emissions Scenarios is flawed

CARB did not properly assess the co-pollutant risk. Co-Pollutant Emissions Assessment is limiting in that it only identifies four "impacted communities" for the purposes of demonstrating the hypothetical bounding exercise and has a problematic boundaries for the communities. ARB should reduce the scale of this assessment to magnify the local communities that are experiencing high exposures to pollution. It is unclear why CARB chose to exclude the West Oakland community and the Port of Oakland and yet, include predominately white, upper class and upper middle class cities such as Piedmont, Orinda and Regional Parks areas in East Contra Costa County. If the intent was to give a regional assessment, CARB should have included the East Bay communities where local PM 2.5 daily concentrations are exceeding federal standards. Low-income communities of color such as in East Oakland are overburdened by exposure to fine particulates and other pollutants and are vulnerable to cumulative impacts[31].

ARB should adopt and utilize the Environmental Justice Screening Method (EJSM) to identify and monitor communities highly impacted by the cumulative emissions. [32] The report states that this is not available on a statewide level, but the academic researcher team stated otherwise to the Environmental Justice Advisory Committee (EJAC) at their June 9, 2010 meeting. The EJAC strongly recommended that CARB utilize the tool to screen for impacted communities throughout the state to meet the requirements and the intent of AB 32[33]. The EJSM may also be used to screen for other categories of impacted communities, whether they are highly impacted or not in order to ensure pollution reductions in communities highly impacted and that no new hot spots are being created, especially in a "medium" impacted community.

ARB includes three scenarios for Community Case Studies (Appendix P-50). We find Scenario 1 – where all covered facilities reduce within the community and use offsets within the community – highly unlikely in the regulation's proposed form in Richmond and Wilmington, due to expected trends in increasing refinery capacities and the unlimited geographic boundaries of the offset program. There are no requirements or

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[30] § 38570(b)(1),(2). (Emphasis added)

[31] Communities for a Better Environment, Lee. East Oakland Particulate Matter 2.5 Community-based Air Monitoring Research Report. 2010. Available at: http://www.cbecal.org/campaigns/oakland.html

[32] See final EJAC comment letter. August 25, 2010.

[33] The final EJAC comment letter on the 'Proposed Screening for Low-Income Communities Highly Impacted by Air Pollution for AB 32 Assessments' dated August 25, 2010 is available for download at: http://www.arb.ca.gov/cc/ejac/ejac.htm

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incentives to do this; in fact the whole regulation is stated to be designed for trading across state and international lines. However, this scenario could be more likely if the regulation is amended to geographically restrict trading and offsets. Scenario 2 – where all covered facilities increase their emissions – seems very likely, especially for sources like refineries, which are attempting to expand and will have to purchase offsets or additional allowances. Scenario 3 – where a new combined heat and power unit at an existing refinery is built in the community – there is a major deficiency in the analysis because it does not account for the possibility that refineries will utilize this increased efficiency in one area of the refinery to allow increased capacity to refine heavier, dirtier crude, resulting in a net increased emissions and exacerbating localized impacts. For example, CARB and the Air Quality Management Districts are well aware that this is the standard approach used in air permitting, and routinely carried out during expansions. Furthermore, due to the flexibility of the proposed regulation, we find the equally apportioned 4% greenhouse gas reduction at every cap-and-trade industrial and electricity generation facility in the community region extremely unrealistic.

Restricted trading zones within already impacted communities

The cap and trade regulation as currently proposed allows significant flexibility and benefits to polluters, but it impermissibly creates environmental justice problems. For example, because the regulation allows off-site reductions, we lose the potential for localized benefits and ARB creates a hard-to-track system that defeats the purpose of public vigilance and accountability. In highly impacted communities, there should be restrictions to trading to ensure meeting the requirements to not exacerbate hot spots of pollutions. Refineries will purchase additional credits or offsets if the cost of reducing greenhouse gases on-site exceeds the costs for other sectors because they can buy credits for a much lower cost. Oil refineries are expanding to accommodate a switch to process heavy crude oil in and around the Richmond and Wilmington communities.[34] Refinery emissions from fuel combustion are predicted to increase two to three times and add 1.6 to 3.7 billion tons greenhouse gas emissions annually from a switch to heavy crude oil or tar sands.[35] If trading is restricted to within these communities, reducing local emissions of criteria and air toxics will benefit the health of these same communities that are already overburdened by pollution. Furthermore, including direct emission reduction measures will ensure real, placed-based reductions, reduce cumulative impacts, and ensure meeting the maximum feasible reductions requirement of AB 32.

II. Many inappropriate exemptions are provided in the proposed regulation

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[34] See CBE's and the EJAC's comments on the Proposed AB 32 Scoping Plan.

[35] Ibid, Karras, G.

Despite the large emissions and low reductions for industrial pollution sources, the regulation goes even further to protect these sources from regulation by providing outright exemptions. For example:

> § 95852.2. Emissions without a Compliance Obligation.
>
> **Emissions from the following source categories** as identified in sections 95100 through 95199 of the Mandatory Reporting Regulation count toward applicable reporting thresholds but **do not count toward a covered entity's compliance obligation set forth in this regulation.** These source categories include:
>
> (f) Fugitive and process emissions from:
>
> **(4) At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations; or**
>
> (5) At the facility types listed in section 95101(e) of the Mandatory Reporting **Regulation, Petroleum and Natural Gas Systems: leak detection and leaker emission factors, and stationary fugitive and "stationary vented" sources on offshore oil platforms.**

Neither a justification for this exemption, nor an evaluation of impacts was provided, nor could we imagine any possible justification. These exemptions are entirely inconsistent with requirements for maximizing reductions and should be struck.

Another exemption is provided for the use of ethanol:

> **§ 95852.2. Emissions without a Compliance Obligation.**
>
> Emissions from the following source categories as identified in sections 95100 through 95199 of the Mandatory Reporting Regulation count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation set forth in this regulation. These source categories include:
>
> (c) Fuel ethanol:
>
> (1) Cellulosic biofuel produced from lignocellulosic or hemicellulosic material that has a proof of at least 150 without regard to denaturants;
>
> (2) Corn starch; or
>
> (3) Sugar cane.

Again, no justification can be provided for this exemption, since ethanol introduction has many environmental impacts in California, the rest of the U.S., and

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internationally, since it greatly increases smog, water pollution, and causes displacement of better land uses. These impacts were documented in CBE's comments on the Scoping Plan, and we refer CARB to those comments, as well as comments made by SCAQMD regarding the problem of the inclusion of ethanol causing increased smog in the region. It is a bad idea to exacerbate this further by giving ethanol a free ride.

III. CARB's accounting systems, particularly the International Forest protection programs (REDD) are vulnerable to fraud, and causes indigenous people's evictions

Three major criticisms of cap and trade schemes are that either the offsets themselves or the trading practices used to account for them are often not verifiable and are fraudulent, and that they can lead to oppression for indigenous communities.[36] The scoping plan proposes to expand a California cap and trade system to other countries where others might benefit from offsets. Put differently, AB32 would allow more pollution in California, including co-pollutants that would concentrate in low-income communities of color, with the hope that other countries will allow clean development. This vision fails to consider that these trades are not verifiable, they are often not surplus, they exacerbate the equivalency problem, and they increase the likelihood of oppression. AB32 specifically requires that the regulations do not disproportionately impact low-income communities,[37] that ARB consider the overall societal benefits of any regulation,[38] and that regulations minimize leakage[39]. These requirements have not been met.

The Indigenous Environmental Network (IEN) has documented severe impacts due to carbon credit trading involving forests, including fake forest protection projects that also cause harm to indigenous people. For example, a company which is responsible for large deforestation projects can clear cut old growth in Southeast Asia, then grow monocropped junk non-native junk trees on the same land, and be paid by fossil fuel polluters to do so. The land must be purchased by the forestry company in order to get paid for the credits. For these reasons, indigenous people are being been evicted from lands after large companies purchase these lands. This is a lose-lose situation for the

[36] For example, the regulations define (#143) "permanent" offsets as offsets that are permanent *or* have a system in place to replace them when they expire. This multilayered system of verification, particularly in an international context, will be extremely hard to monitor.

[37] H&S Code § 38562(b)(2).

[38] H&S Code § 38562(b)(6).

[39] H&S Code § 38562(b)(8).

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environment – no reductions in fossil fuel are carried out because the polluter buys credits from the forestry operator. No forests are protected, and human rights are violated. California's Cap and Trade program, which is seeking to expand internationally it's linkage to other trading programs, is vulnerable to such bad offsets. IEN has published a popular education piece that graphically explains these problems. The publication includes detailed citations documenting examples of such occurrences. We urge CARB to evaluate this information, attached.[40]

IV. The Proposed Regulation Fails to Fulfill the Mandate for Community Investment

Nowhere in the regulations or even in the staff report did ARB describe a strategy to implement the requirement to direct monetary benefits to disadvantaged communities. Yet AB32 requires that,

> The state board shall ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions.[41]

In its discussion of the incomplete Health Impact Assessment, ARB notes that it will explore potential uses of revenue generated by the program to improve public health in California.[42] It also notes that distribution of revenues is an issue that deserves further discussion.[43] While the draft regulation does *recommend* a Community Benefit Fund, as noted in , none of these recommendations commits ARB to any concrete action that would actually move private and public money into disadvantaged communities. Moreover, the section lacks a clear vision on the mechanism for giving a value to the

[40] IEN (Indigenous Environmental Network) Popular Education Piece: *We Want Your Land for Our Climate Fraud!* att http://www.ienearth.org/REDD/redd.pdf ; Top10 - What's Wrong with REDD: http://www.redd-monitor.org/2010/12/03/the-top-10-whats-wrong-with-redd/ ; Forest Destroying Oji Paper company and REDD:
http://www.redd-monitor.org/2010/11/29/forest-destroyer-oji-paper-to-carry-out-redd-feasibility-study-in-laos/#more-6560, Attachment CBE 8 – IEN We Want Your Land for Our Climate Fraud, Attachment CBE 9 – IEN Whats wrong with REDD, and Attachment CBE 10 – IEN Forest Destroying Paper Company

[41] H&S Code § 38565.

[42] Staff Report, page VII-2.

[43] Id., VII-4.

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carbon credits, determining the allocation to the CBF and the best way to direct investments to the communities most impacted by air pollution.

Community Benefits Fund

Communities for a Better Environment was a co-sponsor of AB 1405, De León, California Global Warming Solutions Act of 2006: California Climate Change Community Benefits Fund, which was vetoed by Governor Schwarzenegger recently. This bill would have ensured that the most impacted and disadvantaged communities would get their fair share of revenues and mitigations from the implementation of AB 32. In this piece of legislation, there were three essential components – the creation of the fund, a percentage of revenues generated to fund direct health and environmental mitigations, and a clear definition of the communities to benefit from the fund[44]. Though it did not pass, the inception and development of the bill provides a framework that the staff at CARB could use with amendments.

The amount going to these communities should be significant enough to fund sizeable projects that will have significant environmental benefits to local communities, especially communities living "fenceline" to pollution. Low-income communities tend to pay a higher proportion of their income on water, energy, and food than higher income people and this is expected to increase with the effects of climate change[45]. We recommend allocating no less than 30%.of the total revenues generated from the annual purchase of allowances and offsets that will be allocated to CBF. The revenues should directly benefit local communities most impacted by climate change in California to mitigate the costs of reducing carbon, which disproportionately falls on low-income communities[46]. These communities need funds for planning, adaptation, mitigation, local solutions to reducing greenhouse gases and protecting their health now.

CARB should evaluate communities based on exposure to pollution as well as socioeconomic vulnerability that exacerbate the impacts of pollution. The academic research team of Rachel Morello-Frosch, Manuel Pastor, and Jim Sadd has been working on the EJSM as a product from contract work with the Air Resources Board and we believe this is the closest to the optimal statewide screening methodology for determining communities at the census tract level most impacted by pollution or cumulative impacts.[47] These indicators include: criteria and toxic air pollutant levels, proximity to

[44] AB 1405 information is available at: http://www.leginfo.ca.gov/cgi-bin/postquery?bill_number=ab_1405&sess=PREV&house=B&author=de_leon

[45] Shonkoff SB, Morello-Frosch R, Pastor M, Sadd J. 2009. Environmental Health and Equity Impacts from Climate Change and Mitigation Policies in California: A Review of the Literature. Publication # CEC-500-2009-038-D. Available at: http://www.climatechange.ca.gov/publications/cat/index.html

[46] Shonkoff, *et al.* 2009.

[47] Environmental Justice Screening Methodology. Rachel Morello-Frosch, Jim Sadd, Manuel Pastor. June 9, 2010 Environmental Justice Advisory Committee Meeting. Presentation available for download at: http://www.arb.ca.gov/cc/ejac/meetings/060910/presentation.pdf

hazards, sensitive land use, poverty level, educational attainment, percent home ownership, housing value, sensitive populations (less than 5 years and older than 60 years old), birth outcomes, linguistic isolation, and voter turnout. AB 1405 included unemployment level, while the EJSM does not. We recommend that ARB use the EJSM in the development of the CBF to adequately screen for eligible communities, but also include the communities that may not be included in the screening due to non-incorporated status. The EJSM should also be updated on a frequent and regular basis to accommodate new and developing research and statewide databases.

CARB must develop specific criteria for how the CBF should be used in order to meet AB 32 requirements to ensure low-income communities are not disproportionately impacted and that there are other benefits beyond greenhouse gas reductions[48]. To address the need for stimulating the clean green tech industries, creating job training opportunities for low-income communities, job creation for low-income communities and to address possible disasters such as Hurricane Katrina, CBE recommends including, but not limiting the CBF funding these types of projects:

- projects that reduce both GHGs and co-pollutants in highly impacted communities, including stationary and mobile source pollution;
- non-fossil fuel electricity generating projects in and by local communities;
- green jobs training for low-income residents;
- disaster planning and preparedness, such as flooding, wildfires and other extreme weather events;
- creating community and specific plans to mitigate land use conflicts;
- reducing heat-island effects with strategies such as tree shade planting and "cool pavements";
- improving access to mass transit for low-income riders;
- improving training of industry workers and reducing exposure to pollutants;
- supporting local sustainable agriculture;
- water conservation programs including water catchment projects for homes, roadways and buildings, and greywater use;
- improving water quality in low-income communities;
- and improving or creating park space in low-income communities.

Health Analysis Is Needed

CARB needs to complete and include a health analysis before taking action on the proposed regulation. This assessment would include the existing localized health burdens, the impacts of free allowances, trading, out-of-state offsets, economic impacts

[48] AB 32 requires consideration of "overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health." Health & Safety Code §38562(b)

and directing investments into the most impacted communities. This analysis is crucial to evaluating the proposed regulation.

Thank you for your consideration of our comments.

Sincerely,

Bill Gallegos, Executive Director, EJAC Representative
Adrienne Bloch, Senior Attorney
Julia May, Senior Scientist
Anna Yun Lee, Staff Researcher/ Scientist, Alternate EJAC Representative
Sally Newman, Legal Fellow

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Appendix:

CBE's calculation of NOx Co-Pollutant Reductions achieved if the Industrial Boilers GHG reduction measures CARB identified were achieved In-State[49] (tons per day)

	1. REPLACE BOILERS		2. OPTIMIZE BOILERS		3. FEEDWATER ECONOMIZ		TOTAL 1-3
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	1.26	0.83	0.56	0.23	0.25	0.10	3.23
Food	0.08	0.06	0.05	0.02	0.04	0.02	0.27
Wood Prods	0.09	0.06	0.04	0.02	0.03	0.01	0.26
Chemicals	0.19	0.12	0.08	0.03	0.04	0.02	0.48
Oil and Gas	1.14	0.53	0.36	0.15	0.28	0.11	2.57
Total	**2.76**	**1.61**	**1.10**	**0.45**	**0.64**	**0.26**	**6.81**
	4. AIR PREHEATER		5. BLOWDOWN PRCTC		6. BLOWDWN HEAT RECOV		TOTAL 4-6
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.06	0.03	0.07	0.14	0.13	0.05	0.48
Food	0.01	0.00	0.01	0.02	0.01	0.00	0.05
Wood Prods	0.01	0.00	0.01	0.02	0.01	0.00	0.04
Chemicals	0.01	0.00	0.01	0.02	0.02	0.01	0.07
Oil and Gas	0.05	0.02	0.07	0.13	0.08	0.03	0.38
Total	**0.13**	**0.05**	**0.16**	**0.33**	**0.24**	**0.10**	**1.03**
	7. OPT STEAM QUAL		8. OPT COND REC		9. MINIM. VENTD STEAM		TOTAL 7-9
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.05	0.02	0.07	0.03	0.09	0.03	0.28
Food	0.01	0.00	0.01	0.00	0.01	0.00	0.04
Wood Prods	0.01	0.00	0.01	0.00	0.01	0.00	0.03
Chemicals	0.01	0.00	0.01	0.00	0.01	0.01	0.04
Oil and Gas	0.06	0.02	0.04	0.02	0.08	0.03	0.26
Total	**0.13**	**0.05**	**0.13**	**0.05**	**0.20**	**0.08**	**0.65**
	10 INSUL. MAINT.		11 STEAM TRAP MAINT.		12 STEAM LEAK MAINT.		TOTAL 10-12
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	1.17	0.21	1.26	0.85	0.42	0.17	4.08
Food	0.10	0.02	0.11	0.08	0.04	0.02	0.36
Wood Prods	0.09	0.02	0.09	0.06	0.03	0.01	0.31
Chemicals	0.17	0.03	0.19	0.13	0.06	0.03	0.60
Oil and Gas	0.75	0.14	0.80	0.54	0.27	0.11	2.60
Total	**2.28**	**0.41**	**2.45**	**1.66**	**0.82**	**0.33**	**7.95**
GRAND TOTAL						**Tons per day**	**16.44**
Total from Petroleum, Chemicals, Oil & Gas is biggest portion						**Tons per day**	**15.08**

[49] Using AP42 NOx Emission Factors, based on data CARB provided for MMBTU energy saved for measures above

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(Total shown excludes the small portion from Food & Wood Products)		

<u>CO</u> Co-Pollutant Reductions for <u>Industrial Boilers</u> (tons per day)

	1. REPLACE BOILERS		2. OPTIMIZE BOILERS		3. FEEDWATER ECONOMIZ		TOTAL 1-3
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.38	0.37	0.17	0.10	0.08	0.05	1.14
Food	0.02	0.03	0.01	0.01	0.01	0.01	0.09
Wood Prods	0.03	0.03	0.01	0.01	0.01	0.01	0.09
Chemicals	0.06	0.05	0.03	0.02	0.01	0.01	0.17
Oil and Gas	0.34	0.23	0.11	0.06	0.08	0.05	0.88
Total	**0.83**	**0.71**	**0.33**	**0.20**	**0.19**	**0.12**	**2.37**
	4. AIR PREHEATER		5. BLOWDOWN PRCTC		6. BLOWDWN HEAT RECOV		TOTAL 4-6
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.02	0.01	0.02	0.06	0.04	0.02	0.18
Food	0.00	0.00	0.00	0.01	0.00	0.00	0.02
Wood Prods	0.00	0.00	0.00	0.01	0.00	0.00	0.02
Chemicals	0.00	0.00	0.00	0.01	0.01	0.00	0.03
Oil and Gas	0.01	0.01	0.02	0.06	0.02	0.01	0.14
Total	**0.04**	**0.02**	**0.05**	**0.15**	**0.07**	**0.04**	**0.38**
	7. OPT STEAM QUAL		8. OPT COND REC		9. MINIM. VENTD STEAM		TOTAL 7-9
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.01	0.01	0.02	0.01	0.03	0.02	0.10
Food	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Wood Prods	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Chemicals	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Oil and Gas	0.02	0.01	0.01	0.01	0.02	0.01	0.09
Total	**0.04**	**0.02**	**0.04**	**0.02**	**0.06**	**0.04**	**0.22**
	10 INSUL. MAINT.		11 STEAM TRAP MAINT.		12 STEAM LEAK MAINT.		TOTAL 10-12
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.35	0.09	0.38	0.38	0.13	0.08	1.40
Food	0.03	0.01	0.03	0.03	0.01	0.01	0.12
Wood Prods	0.03	0.01	0.03	0.03	0.01	0.01	0.11
Chemicals	0.05	0.01	0.06	0.06	0.02	0.01	0.21
Oil and Gas	0.22	0.06	0.24	0.24	0.08	0.05	0.89
Total	**0.68**	**0.18**	**0.73**	**0.73**	**0.24**	**0.15**	**2.73**
GRAND TOTAL						**Tons per day**	**5.70**
Total from Petroleum, Chemicals, Oil & Gas is biggest portion (Total shown excludes the small portion from Food & Wood Products)						**Tons per day**	**5.23**

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NOx Co-Pollutant Reductions for Industrial Heaters (tons per day)

	1. REPLACE HEATERS		2. OPTIMIZE HEATERS		3. RECOV. FLUE GAS HEAT		TOTAL 1-3
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	3.03	1.29	1.05	0.43	0.47	0.19	6.44
Food	0.06	0.02	0.02	0.01	0.02	0.01	0.13
Iron & Steel	0.03	0.01	0.01	0.00	0.01	0.00	0.06
Chemical	0.07	0.03	0.02	0.01	0.01	0.00	0.15
Total	**3.19**	**1.35**	**1.10**	**0.45**	**0.50**	**0.20**	**6.79**
	4. REPL BRICK		**5. INSULATION MAINT.**				TOTAL 4-5
	Cat. 1	Cat. 2	Cat. 1	Cat. 2			
Petroleum	0.06	0.03	0.07	0.14			0.30
Food	0.00	0.00	0.01	0.02			0.03
Iron & Steel	0.00	0.00	0.01	0.02			0.02
Chemical	0.00	0.00	0.01	0.02			0.03
Total	**0.07**	**0.05**	**0.10**	**0.33**			**0.55**
GRAND TOTAL						**Tons per day**	**7.35**
Total from Petroleum, Chemicals, Oil & Gas is biggest portion (Total shown excludes the small portion from Food & Wood Products)						**Tons per day**	**7.10**

CO Co-Pollutant Reductions for Industrial Heaters (tons per day)

	1. REPLACE HEATERS		2. OPTIMIZE HEATERS		3. RECOV. FLUE GAS HEAT		TOTAL 1-3
	Cat. 1	Cat. 2	Cat. 1	Cat. 2	Cat. 1	Cat. 2	
Petroleum	0.91	0.57	0.31	0.19	0.14	0.08	2.20
Food	0.02	0.01	0.01	0.00	0.00	0.00	0.05
Iron & Steel	0.01	0.01	0.00	0.00	0.00	0.00	0.02
Chemical	0.02	0.01	0.01	0.00	0.00	0.00	0.05
Total	-	-	-	-	-	-	-
	4. REPL BRICK		**5. INSULATION MAINT.**				TOTAL 4-5
	Cat. 1	Cat. 2	Cat. 1	Cat. 2			
Petroleum	0.02	0.01	0.02	0.06			0.12
Food	0.00	0.00	0.00	0.01			0.01
Iron & Steel	0.00	0.00	0.00	0.01			0.01
Chemical	0.00	0.00	0.00	0.01			0.01
Total	-	-	-	-			-
GRAND TOTAL						**Tons per day**	**2.47**
Total from Petroleum, Chemicals, Oil & Gas is biggest portion (Total shown excludes the small portion from Food & Wood Products)						**Tons per day**	**2.38**

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List of Attachments to CBE Comment 12/15/2010 to CARB on Cap and Trade Regulation

Attachment CBE 1 - ConocoPhillips Rodeo H2 Plant GHGs
Attachment CBE 2 – Previous CBE Comments May 2008 REFINERIES
Attachment CBE 3 – GKarras Environ Sci Technol paper High GHGs D…
Attachment CBE 4 – CBE calcs added to CARB Boiler data
Attachment CBE 5 – CBE calcs added to CARB Heater data
Attachment CBE 6 – AP42 Chapter 1.4
Attachment CBE 7 – SCAQMD Refinery Criteria Pollutants
Attachment CBE 8 – IEN We Want Your Land for Our Climate Fraud
Attachment CBE 9 – IEN Whats wrong with REDD
Attachment CBE 10 – IEN Forest Destroying Paper Company
Attachment CBE 11 – CBE Wilmington_Refineries report

[i] Attachment D, Draft 2007 AQMP Appendix III, Base and Future Year Emissions Inventories, 10/06,

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Proposed Regulation to Implement the California Cap-and-Trade Program: Supplemental Materials for the Compliance Pathways Analysis (Staff Report Chapter V and Appendix F)
Available for download at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm
10/29/2010

Further references for this spreadsheet (i.e., beyond what is listed below) can be found in the Cap-and-Trade Regulation Staff Report References and/or Appendix F.

		Assumptions				Calculations			
Sub-Sector	Percent of Fuel Use By Steam	Boiler Size Category (MMBTU/hr)	Unit Size (MMTBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Number of Total Boilers	Fuel Use Per Unit (MMBTU)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788,400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280,320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420,480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446,760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483,990	10,724,972	141,650,580

Carbon Intensity of Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.053	8760

References	DOE 2010							Einstein et al., 2001	DOE 2002	ARB 2009
Sub-Sector	NAICS Code	Total Fuel (MMBTU)	Fuel to Boilers for Steam (MMBTU)	Fuel to CHP for Steam (MMBTU)	Fuel to Process Heating (MMBTU)	Fuel Used for Steam (percent)	Fuel Used for Process Heating (percent)	Fuel Used for Steam (percent)	Fuel Used for Steam (percent)	Fuel Used for Steam (percent)
Manufacturing	31-33	12,281	2,498	3,162	5,238	46%	43%	-	-	-
Aluminum	3313	120	4	15	92	16%	77%	-	-	-
Cement	327310	341	4	10	315	4%	92%	-	-	-
Chemicals	325	2,417	771	877	488	68%	20%	42%	47%	-
Computers and Electronics	334, 335	87	27	-	27	31%	31%	-	-	-
Fabrication and Metals	332	252	37	2	166	15%	66%	-	-	-
Food and Beverage	311, 312	1,009	458	187	260	64%	26%	57%	-	-
Wood Products	321, 322	2,378	411	1,352	386	74%	16%	81%	84%	-
Foundries	3315	100	6	-	69	6%	69%	-	-	-
Glass	3272, 327993	267	15	-	238	6%	89%	-	-	-
Machinery	333	93	18	6	26	26%	28%	-	-	-
Petroleum	324110	3,020	409	609	1,890	34%	63%	23%	51%	-
Iron and Steel	3311, 3312	994	67	50	758	12%	76%	10%	-	-
Textiles	313, 316	171	86	16	51	60%	30%	-	-	-
Transportation Equipment	336	276	50	7	77	21%	28%	-	-	-
Oil and Gas	-	-	-	-	-	-	-	-	-	70%

California Air Resources Board (ARB) (2009): Oil and Natural Gas Production, Processing, and Storage.
Einstein et al. (2001): Steam Systems in Industry: Energy Use and Energy Efficiency Improvement Potentials. Lawrence Berkeley National Laboratory.
U.S. Department of Energy (DOE) (2002): Steam System Opportunity Assessment for the Pulp and Paper, Chemical Manufacturing, and Petroleum Refining Industry.
U.S. Department of Energy (DOE) (2010): IAC Case Study Database. http://iac.rutgers.edu/database/

CBE Summary of CARB data Industrial Boiler Fuel Reduction (MMBTU) Statewide 2008 data

	1. REPLACE BOILERS		**2. OPTIMIZE BOILERS**		**3. FEEDWATER ECONOMIZI**		**TOTAL 1-3**
Sub Sector	Replace Low Efficiency Boilers (Category 1)	Replace Medium Efficiency Boilers (Category 2)	Reduce Excess Air of Boilers (Category 1)	Reduce Excess Air of Boilers (Category 2)	Retrofit Boilers with Feedwater Economizer (Category 1)	Retrofit Boilers with Feedwater Economizer (Category 2)	
Petroleum	3,339,654	3,258,199	1,500,618	900,371	667,931	400,758	10,067,531
Food	215,398	236,447	132,273	79,364	103,032	61,819	828,333
Wood Products	250,504	244,394	112,560	67,536	87,676	52,606	815,276
Chemicals	493,496	481,459	221,744	133,047	98,699	59,220	1,487,665
Oil and Gas	3,035,370	2,072,935	954,725	572,835	743,666	446,199	7,825,730
Total	7,334,421	6,293,435	2,921,920	1,753,152	1,701,004	1,020,602	**21,024,535**
	4. AIR PREHEATER		**5. BLOWDOWN PRCTCS**		**6. BLOWDOWN HEAT RECO**		**TOTAL 4-6**
Sub Sector	Retrofit Boilers with Air Preheaters (Category 1)	Retrofit Boilers with Air Preheaters (Category 2)	Blowdown Reduction With Controls (Category 1)	Blowdown Reduction with Feedwater Cleanup (Category 2)	Blowdown Heat Recovery (Category 1)	Blowdown Heat Recovery (Category 2)	
Petroleum	166,983	100,190	189,247	567,741	333,965	200,379	1,558,505
Food	17,663	10,598	24,139	72,417	29,438	17,663	171,916
Wood Products	15,030	9,018	20,541	61,624	25,050	15,030	146,294
Chemicals	31,255	18,753	27,965	83,894	49,350	29,610	240,826
Oil and Gas	127,486	76,491	174,230	522,691	212,476	127,486	1,240,859
Total	358,416	215,049	436,122	1,308,367	650,279	390,167	**3,358,401**
	7. OPTIMIZE STEAM QUAL.		**8. OPTIMIZE CONDENS RECO**		**9. MINIMIZE VENTED STEAM**		**TOTAL 7-9**
Sub Sector	Optimize Steam Quality (Category 1)	Optimize Steam Quality (Category 2)	Optimize Condensate Recovery (Category 1)	Optimize Condensate Recovery (Category 2)	Minimize Vented Steam (Category 1)	Minimize Vented Steam (Category 2)	
Petroleum	129,133	77,480	178,115	106,869	228,210	136,926	856,733
Food	22,176	13,306	15,700	9,420	31,400	18,840	110,843
Wood Products	18,871	11,323	13,360	8,016	26,720	16,032	94,323
Chemicals	19,082	11,449	26,320	15,792	33,722	20,233	126,598
Oil and Gas	160,065	96,039	113,320	67,992	216,017	129,610	783,044
Total	349,328	209,597	346,815	208,089	536,070	321,642	**1,971,541**
	10 INSULATION MAINT.		**11 STEAM TRAP MAINT.**		**12 STEAM LEAK MAINT.**		**TOTAL 10-12**
Sub Sector	Insulation Maintenance (Category 1)	Insulation Maintenance (Category 2)	Steam Trap Maintenance (Category 1)	Steam Trap Maintenance (Category 2)	Steam Leak Maintenance (Category 1)	Steam Leak Maintenance (Category 2)	
Petroleum	3,117,011	834,914	3,339,654	3,339,654	1,113,218	667,931	12,412,381
Food	274,752	73,594	294,377	294,377	98,126	58,875	1,094,101
Wood Products	233,804	62,626	250,504	250,504	83,501	50,101	931,040
Chemicals	460,596	123,374	493,496	493,496	164,499	98,699	1,834,160
Oil and Gas	1,983,108	531,190	2,124,759	2,124,759	708,253	424,952	7,897,020
Total	6,069,270	1,625,697	6,502,790	6,502,790	2,167,597	1,300,558	**24,168,702**
GRAND TOTAL							50,523,179
Total from Petroleum, Chemicals, Oil & Gas (Excluding Food & Wood Products)						**Million BTUs**	**46,331,052**
							(Annual)

To calculate NOx & CO CoPollutants, using AP42 Emission Factors:
AP42 - 1.4 Natural Gas Combustion Emission Factors:

	AP42 Factors:			Converting AP42 to lb/MMBTU assuming natural gas, at 1020 MMbtu/MMscf:		
Large Wall-Fired Boilers (>100)	Nox, (lb/ million scf)	CO, (lb/ million scf)	CO2 lbs/million scf	Nox, (lb/ MMBTU)	CO, (lb/ MMBTU	TCO2 /MMBTU
Uncontrolled (Pre-NSPS)c	280	84	120,000	0.275	0.082	0.053
Uncontrolled (Post-NSPS)c	190	84	120,000	0.186	0.082	0.053
Controlled - Low NOx burners	140	84	120,000	0.137	0.082	0.053
Controlled - Flue gas recirculation	100	84	120,000	0.098	0.082	0.053

Natural gas - (lbs/MM scf) /(1020 MM btu/MM scf) = lbs/MMBTU

For comparison SCAQMD refinery inventory:

Total Criteria Emissions South Coast Oil Refinery Emissions Data

(tons per day)	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004	Average of 2001-2002 & 2002-2003 time periods
ROG	8.0	7.7	7.3	8.2	7.9	7.7
NOx	20.1	15.5	13.4	12.8	12.3	13.1
SOx	21.3	19.9	17.2	15.8	14.0	16.5
CO	18.4	14.6	18.2	22.0	21.8	20.1
PM	4.0	4.0	4.0	3.6	3.7	3.8

Estimations assume Category 1 similar to Pre-NSPS Emission Factors
and Category 2 similar to Category 2 Post-NSPS Emission Factors

NOX CO-POLLUTANT REDUCTIONS USING AP42 EMISSION FACTORS **tons/day**

	1. REPLACE BOILERS		**2. OPTIMIZE BOILERS**		**3. FEEDWATER ECONOMIZI**		**TOTAL 1-3**
Sub Sector	Replace Low Efficiency Boilers (Cat. 1) *	Replace Medium Efficiency Boilers (Cat. 2) **	Reduce Excess Air of Boilers (Cat. 1) *	Reduce Excess Air of Boilers (Cat. 2) **	Retrofit Boilers with Feedwater Economizer (Cat. 1) *	Retrofit Boilers with Feedwater Economizer (Cat. 2) **	
Petroleum	1.26	0.83	0.56	0.23	0.25	0.10	3.23
Food	0.08	0.06	0.05	0.02	0.04	0.02	0.27
Wood Products	0.09	0.06	0.04	0.02	0.03	0.01	0.26
Chemicals	0.19	0.12	0.08	0.03	0.04	0.02	0.48
Oil and Gas	1.14	0.53	0.36	0.15	0.28	0.11	2.57
Total	**2.76**	**1.61**	**1.10**	**0.45**	**0.64**	**0.26**	**6.81**
	4. AIR PREHEATER		**5. BLOWDOWN PRCTCS**		**6. BLOWDOWN HEAT RECO**		**TOTAL 4-6**
Sub Sector	Retrofit Boilers with Air Pre-heaters (Cat. 1) *	Retrofit Boilers with Air Preheaters (Cat. 2) *	Blowdown Reduction With Controls (Cat. 1) *	Blowdown Reduction w/Feedwater Cleanup (Cat. 2) **	Blowdown Heat Recovery (Cat. 1) *	Blowdown Heat Recovery (Cat. 2) **	
Petroleum	0.06	0.03	0.07	0.14	0.13	0.05	0.48
Food	0.01	0.00	0.01	0.02	0.01	0.00	0.05
Wood Products	0.01	0.00	0.01	0.02	0.01	0.00	0.04
Chemicals	0.01	0.00	0.01	0.02	0.02	0.01	0.07
Oil and Gas	0.05	0.02	0.07	0.13	0.08	0.03	0.38
Total	**0.13**	**0.05**	**0.16**	**0.33**	**0.24**	**0.10**	**1.03**
	7. OPTIMIZE STEAM QUAL.		**8. OPTIMIZE COND RECOV**		**9. MINIMIZE VENTD STEAM**		**TOTAL 7-9**
Sub Sector	Optimize Steam Quality (Cat. 1)*	Optimize Steam Quality (Cat. 2)**	Optimize Condensate Recovery (Cat. 1)*	Optimize Condensate Recovery (Cat. 2)**	Minimize Vented Steam (Cat. 1)*	Minimize Vented Steam (Cat. 2)**	
Petroleum	0.05	0.02	0.07	0.03	0.09	0.03	0.28
Food	0.01	0.00	0.01	0.00	0.01	0.00	0.04
Wood Products	0.01	0.00	0.01	0.00	0.01	0.00	0.03
Chemicals	0.01	0.00	0.01	0.00	0.01	0.01	0.04
Oil and Gas	0.06	0.02	0.04	0.02	0.08	0.03	0.26
Total	**0.13**	**0.05**	**0.13**	**0.05**	**0.20**	**0.08**	**0.65**
	10 INSULATION MAINT.		**11 STEAM TRAP MAINT.**		**12 STEAM LEAK MAINT.**		**TOTAL 10-12**
Sub Sector	Insulation Maint. (Cat. 1)*	Insulation Maint. (Cat. 2)**	Steam Trap Maint. (Cat. 1)*	Steam Trap Maint. (Cat. 2)**	Steam Leak Maint. (Cat. 1)*	Steam Leak Maint. (Cat. 2)**	
Petroleum	1.17	0.21	1.26	0.85	0.42	0.17	4.08
Food	0.10	0.02	0.11	0.08	0.04	0.02	0.36
Wood Products	0.09	0.02	0.09	0.06	0.03	0.01	0.31
Chemicals	0.17	0.03	0.19	0.13	0.06	0.03	0.60
Oil and Gas	0.75	0.14	0.80	0.54	0.27	0.11	2.60
Total	**2.28**	**0.41**	**2.45**	**1.66**	**0.82**	**0.33**	**7.95**

* using uncontrolled pre NSPS emission factor ** using uncontrolled post NSPS emisssion factor

GRAND TOTAL		**16.44**
Total from Petroleum, Chemicals, Oil & Gas (Excluding Food & Wood Products)	**Tons per day**	**15.08**

CO CO-POLLUTANT REDUCTIONS USING AP42 EMISSION FACTORS

	1. REPLACE BOILERS		2. OPTIMIZE BOILERS		3. FEEDWATER ECONOMIZI		TOTAL 1-3
Sub Sector	Replace Low Efficiency Boilers (Cat. 1) *	Replace Medium Efficiency Boilers (Cat. 2) **	Reduce Excess Air of Boilers (Cat. 1) *	Reduce Excess Air of Boilers (Cat. 2) **	Retrofit Boilers with Feedwater Economizer (Cat. 1) *	Retrofit Boilers with Feedwater Economizer (Cat. 2) **	
Petroleum	0.38	0.37	0.17	0.10	0.08	0.05	1.14
Food	0.02	0.03	0.01	0.01	0.01	0.01	0.09
Wood Products	0.03	0.03	0.01	0.01	0.01	0.01	0.09
Chemicals	0.06	0.05	0.03	0.02	0.01	0.01	0.17
Oil and Gas	0.34	0.23	0.11	0.06	0.08	0.05	0.88
Total	**0.83**	**0.71**	**0.33**	**0.20**	**0.19**	**0.12**	**2.37**
	4. AIR PREHEATER		**5. BLOWDOWN PRCTCS**		**6. BLOWDOWN HEAT RECO**		**TOTAL 4-6**
Sub Sector	Retrofit Boilers with Air Pre-heaters (Cat. 1) *	Retrofit Boilers with Air Preheaters (Cat. 2) *	Blowdown Reduction With Controls (Cat. 1) *	Blowdown Reduction w/Feedwater Cleanup (Cat. 2) **	Blowdown Heat Recovery (Cat. 1) *	Blowdown Heat Recovery (Cat. 2) **	
Petroleum	0.02	0.01	0.02	0.06	0.04	0.02	0.18
Food	0.00	0.00	0.00	0.01	0.00	0.00	0.02
Wood Products	0.00	0.00	0.00	0.01	0.00	0.00	0.02
Chemicals	0.00	0.00	0.00	0.01	0.01	0.00	0.03
Oil and Gas	0.01	0.01	0.02	0.06	0.02	0.01	0.14
Total	**0.04**	**0.02**	**0.05**	**0.15**	**0.07**	**0.04**	**0.38**
	7. OPTIMIZE STEAM QUAL.		**8. OPTIMIZE COND RECOV**		**9. MINIMIZE VENTD STEAM**		**TOTAL 7-9**
Sub Sector	Optimize Steam Quality (Cat. 1)*	Optimize Steam Quality (Cat. 2)**	Optimize Condensate Recovery (Cat. 1)*	Optimize Condensate Recovery (Cat. 2)**	Minimize Vented Steam (Cat. 1)*	Minimize Vented Steam (Cat. 2)**	
Petroleum	0.01	0.01	0.02	0.01	0.03	0.02	0.10
Food	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Wood Products	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Chemicals	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Oil and Gas	0.02	0.01	0.01	0.01	0.02	0.01	0.09
Total	**0.04**	**0.02**	**0.04**	**0.02**	**0.06**	**0.04**	**0.22**
	10 INSULATION MAINT.		**11 STEAM TRAP MAINT.**		**12 STEAM LEAK MAINT.**		**TOTAL 10-12**
Sub Sector	Insulation Maint. (Cat. 1)*	Insulation Maint. (Cat. 2)**	Steam Trap Maint. (Cat. 1)*	Steam Trap Maint. (Cat. 2)**	Steam Leak Maint. (Cat. 1)*	Steam Leak Maint. (Cat. 2)**	
Petroleum	0.35	0.09	0.38	0.38	0.13	0.08	1.40
Food	0.03	0.01	0.03	0.03	0.01	0.01	0.12
Wood Products	0.03	0.01	0.03	0.03	0.01	0.01	0.11
Chemicals	0.05	0.01	0.06	0.06	0.02	0.01	0.21
Oil and Gas	0.22	0.06	0.24	0.24	0.08	0.05	0.89
Total	**0.68**	**0.18**	**0.73**	**0.73**	**0.24**	**0.15**	**2.73**

* using uncontrolled pre NSPS emission factor ** using uncontrolled post NSPS emisssion factor

GRAND TOTAL		**5.70**
Total from Petroleum, Chemicals, Oil & Gas (Excluding Food & Wood Products)	**Tons per day**	**5.23**

Sub-Sector	Percent of Fuel Use By Steam	Assumptions: Boiler Size Category (MMBTU/hr)	Unit Size (MMBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Calculations: Total Number of Boilers	Fuel Use Per Unit (MMBTU/unit)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483990	10,724,972	141,650,580

Sub-Sector	Replace Low Efficiency Boilers (Category 1): Feasibility (percent)	Efficiency of Old Unit (percent)	Efficiency of New Unit (percent)	Efficiency Increase From Low Efficiency Unit (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Replace Medium Efficiency Boilers (Category 2): Feasibility (percent)	Efficiency of Old Unit (percent)	Efficiency of New Unit (percent)	Efficiency Increase From Med Efficiency Unit (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	
Petroleum	15%	80%	88%	10%	42	3,339,654	177,002	20%	82%	88%	7%	56	3,258,199	172,685	
Food	15%	82%	88%	7%	11	215,398	11,416	20%	83%	88%	6%	14	236,447	12,532	
Wood Products	15%	80%	88%	10%	6	250,504	13,277	20%	82%	88%	7%	8	244,394	12,953	
Chemicals	15%	80%	88%	10%	11	493,496	26,155	20%	82%	88%	7%	15	481,459	25,517	
Oil and Gas	15%	77%	88%	14%	44	3,035,370	160,875	20%	82%	88%	7%	59	2,072,935	109,866	
Total						7,334,421	388,724						6,293,435	333,552	-

Unit Size (MMBTU/hr)	Unit Cost for Size	Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e/MMBTU$)	Hours per Year
50	$1,500,000	30%	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Replace Low Efficiency Boilers (Category 1): Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Replace Medium Efficiency Boilers (Category 2): Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$3,000,000	$ 38,325,566	$ 25,681,940	$ 71	$ 3,000,000	$ 51,100,755	$ 25,055,551	$ 151
Food	$1,200,000	$ 3,800,522	$ 1,656,408	$ 188	$ 1,200,000	$ 5,067,363	$ 1,818,279	$ 259
Wood Products	$1,800,000	$ 3,234,107	$ 1,926,376	$ 98	$ 1,800,000	$ 4,312,143	$ 1,879,391	$ 188
Chemicals	$1,800,000	$ 5,996,451	$ 3,794,984	$ 84	$ 1,800,000	$ 7,995,268	$ 3,702,424	$ 168
Oil and Gas	$1,950,000	$ 25,817,863	$ 23,341,992	$ 15	$ 1,950,000	$ 34,423,817	$ 15,940,873	$ 168
Total		$ 77,174,509	$ 56,401,701			$ 102,899,346	$ 48,396,518	

JM ADDED:

Convert to lb/btu assuming natural gas about 1020 btu/scf

AP42:	Large Wall-Fired Boilers (>100)	Nox, (lb/ million scf)	CO, (lb/ million scf)	CO2 lbs/million scf	Nox, (lb/ MMBTU)	CO, (lb/ MMBTU	TCO2 /MMBTU
1.4 Natural Gas Combustion	Uncontrolled (Pre-NSPS)c	280	84	120,000	0.275	0.082	0.053
	Uncontrolled (Post-NSPS)c	190	84	120,000	0.186	0.082	0.053
	Controlled - Low NOx burners	140	84	120,000	0.137	0.082	0.053
	Controlled - Flue gas recirculation	100	84	120,000	0.098	0.082	0.053

Natural gas: (lbs/MM scf) /(1020 MM btu/MM scf) = lbs/MMBTU

#VALUE!	0	#VALUE!	0			
#VALUE!	0	#VALUE!	0			
0	0	0	0			
0	0	0	0			
0	0	0	0			
	#VALUE!		#VALUE!			

Sub-Sector	Percent of Fuel Use By Steam	Assumptions: Boiler Size Category (MMBTU/hr)	Unit Size (MMBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Calculations: Total Number of Boilers	Fuel Use per Unit (MMBTU)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483990	10,724,972	141,650,580

Sub-Sector	Reduce Excess Air of Boilers (Category 1): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Reduce Excess Air of Boilers (Category 2): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	34%	2%	95	1,500,618	79,533	40%	1%	114	900,371	47,720
Food	34%	2%	24	132,273	7,010	40%	1%	28	79,364	4,206
Wood Products	34%	2%	13	112,560	5,966	40%	1%	16	67,536	3,579
Chemicals	34%	2%	25	221,744	11,752	40%	1%	30	133,047	7,051
Oil and Gas	34%	2%	99	954,725	50,600	40%	1%	118	572,835	30,360
Total				2,921,920	154,862				1,753,152	92,917

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Reduce Excess Air of Boilers (Category 1): Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Reduce Excess Air of Boilers (Category 2): Price Per Unit[1]	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 121,256	$ 3,480,238	$ 11,539,752	$ (101)	$ 181,884	$ 5,220,357	$ 6,923,851	$ (36)
Food	$ 43,113	$ 306,769	$ 1,017,182	$ (101)	$ 64,670	$ 460,153	$ 610,309	$ (36)
Wood Products	$ 64,670	$ 261,049	$ 865,585	$ (101)	$ 97,005	$ 391,574	$ 519,351	$ (36)
Chemicals	$ 68,712	$ 514,270	$ 1,705,213	$ (101)	$ 103,068	$ 771,405	$ 1,023,128	$ (36)
Oil and Gas	$ 74,438	$ 2,214,201	$ 7,341,835	$ (101)	$ 111,656	$ 3,321,302	$ 4,405,101	$ (36)
Total		$ 6,776,526	$ 22,469,566			$10,164,790	$ 13,481,740	

[1] For Category 2, staff assumed a 50 percent greater cost than Category 1

JM ADDED:

Convert to lb/btu assuming natural gas about 1020 btu/scf

AP42:	Large Wall-Fired Boilers (>100)	Nox, (lb/ million scf)	CO, (lb/ million scf)	CO2 lbs/million scf	Nox, (lb/ MMBTU)	CO, (lb/ MMBTU	TCO2 /MMBTU
1.4 Natural Gas Combustion	Uncontrolled (Pre-NSPS)c	280	84	120,000	0.275	0.082	0.053

Uncontrolled (Post-NSPS)c	190	84	120,000	0.186	0.082	0.053
Controlled - Low NOx burners	140	84	120,000	0.137	0.082	0.053
Controlled - Flue gas recirculation	100	84	120,000	0.098	0.082	0.053

Natural gas: (lbs/MM scf) /(1020 MM btu/MM scf) = lbs/MMBTU

Sub-Sector	Percent of Fuel Use By Steam	Assumptions: Boiler Size Category (MMBTU/hr)	Unit Size (MMBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Calculations: Total Number of Boilers	Fuel Use per Unit (MMBTU)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483990	10,724,972	141,650,580

Sub-Sector	Retrofit Boilers with Feedwater Economizer (Category 1)					Retrofit Boilers with Feedwater Economizer (Category 2)				
	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	15%	2%	42	667,931	35,400	18%	1%	51	400,758	21,240
Food	15%	4%	11	103,032	5,461	18%	2%	13	61,819	3,276
Wood Products	15%	4%	6	87,676	4,647	18%	2%	7	52,606	2,788
Chemicals	15%	2%	11	98,699	5,231	18%	1%	13	59,220	3,139
Oil and Gas	15%	4%	44	743,666	39,414	18%	2%	53	446,199	23,649
Total				1,701,004	90,153				1,020,602	54,092

Unit Size (MMBTU/hr)	Unit Cost for Size	Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
50	$ 250,000	30%	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Retrofit Boilers with Feedwater Economizer (Category 1)				Retrofit Boilers with Feedwater Economizer (Category 2)			
	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 500,000	$ 6,387,594	$ 5,133,115	$ 35	$ 500,000	$ 6,387,594	$ 3,079,869	$ 156
Food	$ 200,000	$ 633,420	$ 791,810	$ (29)	$ 200,000	$ 633,420	$ 475,086	$ 48
Wood Products	$ 300,000	$ 539,018	$ 673,802	$ (29)	$ 300,000	$ 539,018	$ 404,281	$ 48
Chemicals	$ 300,000	$ 999,409	$ 758,513	$ 46	$ 300,000	$ 999,409	$ 455,108	$ 173
Oil and Gas	$ 325,000	$ 4,302,977	$ 5,715,144	$ (36)	$ 325,000	$ 4,302,977	$ 3,429,086	$ 37
Total		$ 12,862,418	$ 13,072,385			$ 12,862,418	$ 7,843,431	

Sub-Sector	Assumptions: Percent of Fuel Use By Steam	Boiler Size Category (MMBTU/hr)	Unit Size (MMBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Calculations: Total Number of Boilers	Fuel Use per Unit (MMBTU)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788,400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280,320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420,480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446,760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483,990	10,724,972	141,650,580

Sub-Sector	Retrofit Boilers with Air Preheaters (Category 1): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Retrofit Boilers with Air Preheaters (Category 2): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	5%	2%	14	166,983	8,850	6%	1%	17	100,190	5,310
Food	5%	2%	4	17,663	936	6%	1%	4	10,598	562
Wood Products	5%	2%	2	15,030	797	6%	1%	2	9,018	478
Chemicals	5%	2%	4	31,255	1,657	6%	1%	4	18,753	994
Oil and Gas	5%	2%	15	127,486	6,757	6%	1%	18	76,491	4,054
Total				358,416	18,996				215,049	11,398

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Retrofit Boilers with Air Preheaters (Category 1): Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Retrofit Boilers with Air Preheaters (Category 2): Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 181,768	$ 774,040	$ 1,283,279	$ (58)	$ 181,768	$ 928,848	$ 769,967	$ 30
Food	$ 93,065	$ 98,249	$ 135,739	$ (40)	$ 93,065	$ 117,899	$ 81,443	$ 65
Wood Products	$ 139,598	$ 83,606	$ 115,509	$ (40)	$ 139,598	$ 100,328	$ 69,305	$ 65
Chemicals	$ 169,610	$ 188,344	$ 240,196	$ (31)	$ 169,610	$ 226,013	$ 144,118	$ 82
Oil and Gas	$ 160,683	$ 709,143	$ 979,739	$ (40)	$ 160,683	$ 850,972	$ 587,843	$ 65
Total		$ 1,853,383	$ 2,754,461			$ 2,224,059	$ 1,652,677	

Sub-Sector	Percent of Fuel Use By Steam	Assumptions: Boiler Size Category (MMBTU/hr)	Unit Size (MMBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Calculations: Total Number of Boilers	Fuel Use Per Unit (MMBTU)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788,400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280,320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420,480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446,760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483,990	10,724,972	141,650,580

Sub-Sector	Blowdown Reduction With Controls (Category 1): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Blowdown Reduction with Feedwater Cleanup (Category 2): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	8.5%	1%	24	189,247	10,030	13%	2%	36	567,741	30,090
Food	12.3%	1%	9	24,139	1,279	18%	2%	13	72,417	3,838
Wood Products	12.3%	1%	5	20,541	1,089	18%	2%	7	61,624	3,266
Chemicals	8.5%	1%	6	27,965	1,482	13%	2%	9	83,894	4,446
Oil and Gas	12.3%	1%	36	174,230	9,234	18%	2%	54	522,691	27,703
Total				436,122	23,114			119.6377945	1,308,367	69,343

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Emissions of Natural Gas ($MMTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Blowdown Reduction With Controls (Category 1): Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Blowdown Reduction with Feedwater Cleanup (Category 2): Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 181,768	$ 1,315,868	$ 1,454,383	$ (14)	$ 484,715	$ 5,263,473	$ 4,363,148	$ 30
Food	$ 64,629	$ 167,842	$ 185,510	$ (14)	$ 172,343	$ 671,368	$ 556,530	$ 30
Wood Products	$ 96,943	$ 142,828	$ 157,862	$ (14)	$ 258,514	$ 571,310	$ 473,587	$ 30
Chemicals	$ 103,002	$ 194,444	$ 214,912	$ (14)	$ 274,672	$ 777,776	$ 644,736	$ 30
Oil and Gas	$ 111,585	$ 1,211,453	$ 1,338,977	$ (14)	$ 297,561	$ 4,845,813	$ 4,016,930	$ 30
Total		$ 3,032,435	$ 3,351,643			$ 12,129,740	$ 10,054,930	

Sub-Sector	Percent of Fuel Use By Steam	Assumptions				Calculations			
		Boiler Size Range (MMBTU/hr)	Boiler Size (MMBTU/hr)	Efficiency (percent)	Capacity Factor (staff estimate) (percent)	Total Numbers of Boilers	Fuel Use Per Unit (MMBTU)	2008 Emissions ($MTCO_2e$)	Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	>60	100	80-83	0.90	282	788400	35,006,224	222,643,608
Food	64%	10-100	40	82-83	0.80	70	280320	1,627,120	19,625,123
Wood Products	74%	>50	60	80-83	0.80	40	420480	1,193,875	16,700,271
Chemicals	68%	>50	60	80-83	0.85	74	446760	2,557,335	32,899,732
Oil and Gas	70%	50-100	65	77-82	0.85	293	483990	10,724,972	141,650,580

Sub-Sector	Blowdown Heat Recovery (Category 1)					Blowdown Heat Recovery (Category 2)				
	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	15%	1%	42	333,965	17,700	18%	1%	51	200,379	10,620
Food	15%	1%	11	29,438	1,560	18%	1%	13	17,663	936
Wood Products	15%	1%	6	25,050	1,328	18%	1%	7	15,030	797
Chemicals	15%	1%	11	49,350	2,616	18%	1%	13	29,610	1,569
Oil and Gas	15%	1%	44	212,476	11,261	18%	1%	53	127,486	6,757
Total				650,279	34,465				390,167	20,679

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Emissions of Natural Gas ($MMTCO_2e$/MMBTU)	Hours in Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Blowdown Heat Recovery (Category 1)				Blowdown Heat Recovery (Category 2)			
	Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Price Per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 121,179	$ 1,548,080	$ 2,566,558	$ (58)	$ 121,179	$ 1,548,080	$ 1,539,935	$ 1
Food	$ 43,086	$ 136,457	$ 226,232	$ (58)	$ 43,086	$ 136,457	$ 135,739	$ 1
Wood Products	$ 64,629	$ 116,120	$ 192,515	$ (58)	$ 64,629	$ 116,120	$ 115,509	$ 1
Chemicals	$ 68,668	$ 228,758	$ 379,257	$ (58)	$ 68,668	$ 228,758	$ 227,554	$ 1
Oil and Gas	$ 74,390	$ 984,921	$ 1,632,898	$ (58)	$ 74,390	$ 984,921	$ 979,739	$ 1
Total		$ 3,014,336	$ 4,997,459			$ 3,014,336	$ 2,998,475	

Sub-Sector	Percent of Fuel Use By Steam	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	35,006,224	222,643,608
Food	64%	1,627,120	19,625,123
Wood Products	74%	1,193,875	16,700,271
Chemicals	68%	2,557,335	32,899,732
Oil and Gas	70%	10,724,972	141,650,580

Sub-Sector	Optimize Steam Quality (Category 1)				Optimize Steam Quality (Category 2)			
	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	5.8%	1.0%	129,133	6,844	7.0%	0.5%	77,480	4,106
Food	11.3%	1.0%	22,176	1,175	13.6%	0.5%	13,306	705
Wood Products	11.3%	1.0%	18,871	1,000	13.6%	0.5%	11,323	600
Chemicals	5.8%	1.0%	19,082	1,011	7.0%	0.5%	11,449	607
Oil and Gas	11.3%	1.0%	160,065	8,483	13.6%	0.5%	96,039	5,090
Total			349,328	18,514			209,597	11,109

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Emissions of Natural Gas ($MMTCO_2e$/MMBTU)	Hours in Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Optimize Steam Quality (Category 1)				Optimize Steam Quality (Category 2)			
	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 1,488,603	$ 448,943	$ 992,402	$ (79)	$ 1,488,603	$ 448,943	$ 595,441	$ (36)
Food	$ 255,642	$ 77,098	$ 170,428	$ (79)	$ 255,642	$ 77,098	$ 102,257	$ (36)
Wood Products	$ 217,542	$ 65,608	$ 145,028	$ (79)	$ 217,542	$ 65,608	$ 87,017	$ (36)
Chemicals	$ 219,969	$ 66,340	$ 146,646	$ (79)	$ 219,969	$ 66,340	$ 87,988	$ (36)
Oil and Gas	$ 1,845,175	$ 556,481	$ 1,230,117	$ (79)	$ 1,845,175	$ 556,481	$ 738,070	$ (36)
Total		$ 1,214,470	$ 2,684,621			$ 1,214,470	$ 1,610,772	

Sub-Sector	Percent of Fuel Use By Steam	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	35,006,224	222,643,608
Food	64%	1,627,120	19,625,123
Wood Products	74%	1,193,875	16,700,271
Chemicals	68%	2,557,335	32,899,732
Oil and Gas	70%	10,724,972	141,650,580

	Optimize Condensate Recovery (Category 1)				Optimize Condensate Recovery (Category 2)			
Sub-Sector	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	20%	0.4%	178,115	9,440	24%	0.2%	106,869	5,664
Food	20%	0.4%	15,700	832	24%	0.2%	9,420	499
Wood Products	20%	0.4%	13,360	708	24%	0.2%	8,016	425
Chemicals	20%	0.4%	26,320	1,395	24%	0.2%	15,792	837
Oil and Gas	20%	0.4%	113,320	6,006	24%	0.2%	67,992	3,604
Total			346,815	18,381			208,089	11,029

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Emissions of Natural Gas ($MMTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

	Optimize Condensate Recovery (Category 1)				Optimize Condensate Recovery (Category 2)			
Sub-Sector	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 3,422,077	$ 1,032,053	$ 1,368,831	$ (36)	$ 3,422,077	$ 1,032,053	$ 821,298	$ 37
Food	$ 301,642	$ 90,971	$ 120,657	$ (36)	$ 301,642	$ 90,971	$ 72,394	$ 37
Wood Products	$ 256,687	$ 77,413	$ 102,675	$ (36)	$ 256,687	$ 77,413	$ 61,605	$ 37
Chemicals	$ 505,675	$ 152,505	$ 202,270	$ (36)	$ 505,675	$ 152,505	$ 121,362	$ 37
Oil and Gas	$ 2,177,198	$ 656,614	$ 870,879	$ (36)	$ 2,177,198	$ 656,614	$ 522,527	$ 37
Total		$ 2,009,557	$ 2,665,311			$ 2,009,557	$ 1,599,187	

Sub-Sector	Percent of Fuel Use By Steam	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	35,006,224	222,643,608
Food	64%	1,627,120	19,625,123
Wood Products	74%	1,193,875	16,700,271
Chemicals	68%	2,557,335	32,899,732
Oil and Gas	70%	10,724,972	141,650,580

Sub-Sector	Minimize Vented Steam (Category 1)				Minimize Vented Steam (Category 2)			
	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	4.1%	2.5%	228,210	12,095	4.9%	1.3%	136,926	7,257
Food	6.4%	2.5%	31,400	1,664	7.7%	1.3%	18,840	999
Wood Products	6.4%	2.5%	26,720	1,416	7.7%	1.3%	16,032	850
Chemicals	4.1%	2.5%	33,722	1,787	4.9%	1.3%	20,233	1,072
Oil and Gas	6.1%	2.5%	216,017	11,449	7.3%	1.3%	129,610	6,869
Total			536,070	28,412			321,642	17,047

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Minimize Vented Steam (Category 1)				Minimize Vented Steam (Category 2)			
	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 876,907	$ 264,464	$ 1,753,814	$ (123)	$ 876,907	$ 264,464	$ 1,052,289	$ (109)
Food	$ 120,657	$ 36,389	$ 241,314	$ (123)	$ 120,657	$ 36,389	$ 144,788	$ (109)
Wood Products	$ 102,675	$ 30,965	$ 205,349	$ (123)	$ 102,675	$ 30,965	$ 123,210	$ (109)
Chemicals	$ 129,579	$ 39,079	$ 259,159	$ (123)	$ 129,579	$ 39,079	$ 155,495	$ (109)
Oil and Gas	$ 830,057	$ 250,334	$ 1,660,113	$ (123)	$ 830,057	$ 250,334	$ 996,068	$ (109)
Total		$ 621,231	$ 4,119,749			$ 621,231	$ 2,471,849	

Sub-Sector	Percent of Fuel Use By Steam	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	35,006,224	222,643,608
Food	64%	1,627,120	19,625,123
Wood Products	74%	1,193,875	16,700,271
Chemicals	68%	2,557,335	32,899,732
Oil and Gas	70%	10,724,972	141,650,580

	Insulation Maintenance (Category 1)				Insulation Maintenance (Category 2)			
Sub-Sector	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	40%	3.5%	3,117,011	165,202	5%	7.5%	834,914	44,250
Food	40%	3.5%	274,752	14,562	5%	7.5%	73,594	3,900
Wood Products	40%	3.5%	233,804	12,392	5%	7.5%	62,626	3,319
Chemicals	40%	3.5%	460,596	24,412	5%	7.5%	123,374	6,539
Oil and Gas	40%	3.5%	1,983,108	105,105	5%	7.5%	531,190	28,153
Total			6,069,270	321,671			1,625,697	86,162

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

	Insulation Maintenance (Category 1)				Insulation Maintenance (Category 2)			
Sub-Sector	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 47,909,075	$14,448,749	$ 23,954,537	$ (58)	$ 19,249,182	$ 5,774,755	$ 6,416,394	$ (15)
Food	$ 4,222,989	$ 1,273,598	$ 2,111,494	$ (58)	$ 1,696,737	$ 509,021	$ 565,579	$ (15)
Wood Products	$ 3,593,611	$ 1,083,786	$ 1,796,806	$ (58)	$ 1,443,862	$ 433,158	$ 481,287	$ (15)
Chemicals	$ 7,079,456	$ 2,135,071	$ 3,539,728	$ (58)	$ 2,844,424	$ 853,327	$ 948,141	$ (15)
Oil and Gas	$ 30,480,768	$ 9,192,600	$ 15,240,384	$ (58)	$ 12,246,737	$ 3,674,021	$ 4,082,246	$ (15)
Total		$28,133,804	$ 46,642,950			$ 11,244,283	$12,493,647	

Sub-Sector	Percent of Fuel Use By Steam	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	35,006,224	222,643,608
Food	64%	1,627,120	19,625,123
Wood Products	74%	1,193,875	16,700,271
Chemicals	68%	2,557,335	32,899,732
Oil and Gas	70%	10,724,972	141,650,580

	Steam Trap Maintenance (Category 1)				Steam Trap Maintenance (Category 2)			
Sub-Sector	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	50%	3%	3,339,654	177,002	30%	5.0%	3,339,654	177,002
Food	50%	3%	294,377	15,602	30%	5.0%	294,377	15,602
Wood Products	50%	3%	250,504	13,277	30%	5.0%	250,504	13,277
Chemicals	50%	3%	493,496	26,155	30%	5.0%	493,496	26,155
Oil and Gas	50%	3%	2,124,759	112,612	30%	5.0%	2,124,759	112,612
Total			6,502,790	344,648			6,502,790	344,648

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

	Steam Trap Maintenance (Category 1)				Steam Trap Maintenance (Category 2)			
Sub-Sector	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Total Capital Cost[1]	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 25,665,576	$ 7,740,401	$ 25,665,576	$ (101)	$ 38,498,364	$ 11,549,509	$ 25,665,576	$ (80)
Food	$ 2,262,316	$ 682,285	$ 2,262,316	$ (101)	$ 3,393,473	$ 1,018,042	$ 2,262,316	$ (80)
Wood Products	$ 1,925,149	$ 580,600	$ 1,925,149	$ (101)	$ 2,887,723	$ 866,317	$ 1,925,149	$ (80)
Chemicals	$ 3,792,566	$ 1,143,788	$ 3,792,566	$ (101)	$ 5,688,849	$ 1,706,655	$ 3,792,566	$ (80)
Oil and Gas	$ 16,328,983	$ 4,924,607	$ 16,328,983	$ (101)	$ 24,493,475	$ 7,348,042	$ 16,328,983	$ (80)
Total		$ 15,071,681	$ 49,974,589			$ 22,488,565	$ 49,974,589	

[1] For Category 2, staff assumed a 50 percent greater cost than Category 1

Sub-Sector	Percent of Fuel Use By Steam	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Amount of Natural Gas to Produce Steam (MMBTU)
Petroleum	34%	35,006,224	222,643,608
Food	64%	1,627,120	19,625,123
Wood Products	74%	1,193,875	16,700,271
Chemicals	68%	2,557,335	32,899,732
Oil and Gas	70%	10,724,972	141,650,580

Sub-Sector	Steam Leak Maintenance (Category 1)				Steam Leak Maintenance (Category 2)			
	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	20%	2.5%	1,113,218	59,001	30%	1.0%	667,931	35,400
Food	20%	2.5%	98,126	5,201	30%	1.0%	58,875	3,120
Wood Products	20%	2.5%	83,501	4,426	30%	1.0%	50,101	2,655
Chemicals	20%	2.5%	164,499	8,718	30%	1.0%	98,699	5,231
Oil and Gas	20%	2.5%	708,253	37,537	30%	1.0%	424,952	22,522
Total			2,167,597	114,883			1,300,558	68,930

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Steam Leak Maintenance (Category 1)				Steam Leak Maintenance (Category 2)			
	Total Capital Cost	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Total Capital Cost[1]	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 12,832,788	$ 3,870,201	$ 8,555,192	$ (79)	$ 19,249,182	$ 5,805,301	$ 5,133,115	$ 19
Food	$ 1,131,158	$ 341,142	$ 754,105	$ (79)	$ 1,696,737	$ 511,714	$ 452,463	$ 19
Wood Products	$ 962,574	$ 290,300	$ 641,716	$ (79)	$ 1,443,862	$ 435,450	$ 385,030	$ 19
Chemicals	$ 1,896,283	$ 571,894	$ 1,264,189	$ (79)	$ 2,844,424	$ 857,841	$ 758,513	$ 19
Oil and Gas	$ 8,164,492	$ 2,462,304	$ 5,442,994	$ (79)	$ 12,246,737	$ 3,693,455	$ 3,265,797	$ 19
Total		$ 7,535,840	$ 16,658,196			$ 11,303,761	$ 9,994,918	

[1] For Category 2, staff assumed a 50 percent greater cost than Category 1

CBE Summary of CARB Potential for Industrial Boiler Fuel Reduction (MMBTU) Statewide,
2008 data from CARB spreadsheet

	1. REPLACE HEATERS		**2. OPTIMIZE HEATERS**		**3. RECOV. FLUE GAS HEAT**		**TOTAL 1-3**
Sub Sector	Replace Low Efficiency Process Heaters	Replace Medium Efficiency Process Heaters	Optimize Process Heater (Category 1)	Optimize Process Heater (Category 2)	Recover Flue Gas Heat (Category 1)	Recover Flue Gas Heat (Category 2)	
Petroleum	8,052,390	5,040,927	2,786,020	1,671,612	1,240,068	744,041	19,535,057
Food	154,108	96,474	53,319	31,992	41,532	24,919	402,346
Iron and Steel	73,911	46,269	25,572	15,343	19,919	11,951	192,965
Chemical	189,782	118,807	65,662	39,397	29,226	17,536	460,411
							0
Total	8,470,191	5,302,477	2,930,573	1,758,344	1,330,746	798,447	**20,590,779**
	4. REPLACEREFRACT. BRIC		**5. INSULATION MAINT.**				**TOTAL 4-5**
Sub Sector	Replace Refractory Brick (Category 1)	Replace Refractory Brick (Category 2)	Insulation Maintenance (Category 1)	Insulation Maintenance (Category 2)			
Petroleum	165,342	99,205	189,247	567,741			1,021,536
Food	3,164	1,899	24,139	72,417			101,619
Iron and Steel	1,518	911	20,541	61,624			84,594
Chemical	3,897	2,338	27,965	83,894			118,094
							0
Total	358,416	215,049	436,122	1,308,367			**2,317,954**
GRAND TOTAL							**22,908,733**
Total Petroleum & Chemical (excluding Iron & Steel, & Food)						**Million BTUs**	**22,127,210**
							(Annual)

To calculate NOx & CO CoPollutants, using AP42 Emission Factors:
AP42 - 1.4 Natural Gas Combustion Emission Factors:

	AP42 Factors:			Converting AP42 to lb/MMBTU assuming natural gas, at 1020 MMbtu/MMscf:		
Large Wall-Fired Boilers (>100)	Nox, (lb/ million scf)	CO, (lb/ million scf)	CO2 lbs/million scf	Nox, (lb/ MMBTU)	CO, (lb/ MMBTU	TCO2 /MMBTU
Uncontrolled (Pre-NSPS)c	280	84	120,000	0.275	0.082	0.053
Uncontrolled (Post-NSPS)c	190	84	120,000	0.186	0.082	0.053
Controlled - Low NOx burners	140	84	120,000	0.137	0.082	0.053
Controlled - Flue gas recirculation	100	84	120,000	0.098	0.082	0.053

Natural gas - (lbs/MM scf) /(1020 MM btu/MM scf) = lbs/MMBTU

For comparison SCAQMD refinery inventory:

Total Criteria Emissions South Coast Oil Refinery Emissions Data

(tons per day)	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004	Average of 2001-2002 & 2002-2003 time periods
ROG	8.0	7.7	7.3	8.2	7.9	7.7
NOx	20.1	15.5	13.4	12.8	12.3	13.1
SOx	21.3	19.9	17.2	15.8	14.0	16.5
CO	18.4	14.6	18.2	22.0	21.8	20.1
PM	4.0	4.0	4.0	3.6	3.7	3.8

Estimations assume Category 1 similar to Pre-NSPS Emission Factors
and Category 2 similar to Category 2 Post-NSPS Emission Factors

NOX CO-POLLUTANT REDUCTIONS USING AP42 EMISSION FACTORS TONS PER DAY

	1. REPLACE HEATERS		2. OPTIMIZE HEATERS		3. RECOV. FLUE GAS HEAT		TOTAL 1-3
Sub Sector	Replace Low Efficiency Process Heaters	Replace Medium Efficiency Process Heaters	Optimize Process Heater (Category 1)	Optimize Process Heater (Category 2)	Recover Flue Gas Heat (Category 1)	Recover Flue Gas Heat (Category 2)	
Petroleum	3.03	1.29	1.05	0.43	0.47	0.19	6.44
Food	0.06	0.02	0.02	0.01	0.02	0.01	0.13
Iron and Steel	0.03	0.01	0.01	0.00	0.01	0.00	0.06
Chemical	0.07	0.03	0.02	0.01	0.01	0.00	0.15
	-	-	-	-	-	-	-
Total	**3.19**	**1.35**	**1.10**	**0.45**	**0.50**	**0.20**	**6.79**
	4. REPLACE	**REFRACT. BRIC**	**5. INSULATION MAINT.**				**TOTAL 4-5**
Sub Sector	Replace Refractory Brick (Category 1)	Replace Refractory Brick (Category 2)	Insulation Maintenance (Category 1)	Insulation Maintenance (Category 2)			
Petroleum	0.06	0.03	0.07	0.14	-	-	0.30
Food	0.00	0.00	0.01	0.02	-	-	0.03
Iron and Steel	0.00	0.00	0.01	0.02	-	-	0.02
Chemical	0.00	0.00	0.01	0.02	-	-	0.03
	-	-	-	-	-	-	-
Total	**0.07**	**0.05**	**0.10**	**0.33**	**-**	**-**	**0.55**

* using uncontrolled pre NSPS emission factor ** using uncontrolled post NSPS emisssion factor

GRAND TOTAL		**7.35**
Total Petroleum & Chemical (excluding Iron & Steel, & Food)	**Tons per day**	**7.10**

CO CO-POLLUTANT REDUCTIONS USING AP42 EMISSION FACTORS

	1. REPLACE HEATERS		2. OPTIMIZE HEATERS		3. RECOV. FLUE GAS HEAT		TOTAL 1-3
Sub Sector	Replace Low Efficiency Process Heaters	Replace Medium Efficiency Process Heaters	Optimize Process Heater (Category 1)	Optimize Process Heater (Category 2)	Recover Flue Gas Heat (Category 1)	Recover Flue Gas Heat (Category 2)	
Petroleum	0.91	0.57	0.31	0.19	0.14	0.08	2.20
Food	0.02	0.01	0.01	0.00	0.00	0.00	0.05
Iron and Steel	0.01	0.01	0.00	0.00	0.00	0.00	0.02
Chemical	0.02	0.01	0.01	0.00	0.00	0.00	0.05
	-	-	-	-	-	-	-
Total	**0.96**	**0.60**	**0.33**	**0.20**	**0.15**	**0.09**	**2.32**
	4. REPLACE	**REFRACT. BRIC**	**5. INSULATION MAINT.**				**TOTAL 4-5**
Sub Sector	Replace Refractory Brick (Category 1)	Replace Refractory Brick (Category 2)	Insulation Maintenance (Category 1)	Insulation Maintenance (Category 2)			
Petroleum	0.02	0.01	0.02	0.06	-	-	0.12
Food	0.00	0.00	0.00	0.01	-	-	0.01
Iron and Steel	0.00	0.00	0.00	0.01	-	-	0.01
Chemical	0.00	0.00	0.00	0.01	-	-	0.01
	-	-	-	-	-	-	-
Total	**0.02**	**0.01**	**0.03**	**0.09**	**-**	**-**	**0.15**

* using uncontrolled pre NSPS emission factor ** using uncontrolled post NSPS emisssion factor

GRAND TOTAL		**2.47**
Total Petroleum & Chemical (excluding Iron & Steel, & Food)	**Tons per day**	**2.38**

Proposed Regulation to Implement the California Cap-and-Trade Program: Supplemental Materials for the Compliance Pathways Analysis (Staff Report Chapter V and Appendix F)
Available for download at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm
10/29/2010

References for this spreadsheet can be found in the Cap-and-Trade Regulation Staff Report References and/or Appendix F.

		Assumptions				Calculations			
Sub-Sector	Percent of Fuel Used By Process Heat	Process Heater Size Range (MMBTU/hr)	Process Heater Size (staff estimate) (MMBTU/hr)	Process Heater Efficiency (staff estimate[1]) (percent)	Capacity (staff estimate) (percent)	Number of Total Process Heaters	Average Process Heater Fuel Use (MMBTU)	2008 Emissions ($MTCO_2e$)	Number of Entities
Petroleum	63%	>60	100	77–83	0.9	524	788,400	35,006,224	413,356,010
Food	26%	10–30	20	77–83	0.8	56	140,160	1,627,120	7,910,902
Iron and Steel	76%	10–100	40	77–83	0.8	14	280,320	263,693	3,794,077
Chemical	20%	10–100	50	77–83	0.85	26	372,300	2,557,335	9,742,154

	Replace Low Efficiency Process Heaters							Replace Medium Efficiency Process Heaters						
Sub-Sector	Feasibility (percent)	Efficiency of Old Unit (percent)	Efficiency of New Unit (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency of Old Unit (percent)	Efficiency of New Unit (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	15%	77%	87%	13%	79	8,052,390	426,777	20%	82%	87%	6%	105	5,040,927	267,169
Food	15%	77%	87%	13%	8	154,108	8,168	20%	82%	87%	6%	11	96,474	5,113
Iron and Steel	15%	77%	87%	13%	2	73,911	3,917	20%	82%	87%	6%	3	46,269	2,452
Chemical	15%	77%	87%	13%	4	189,782	10,058	20%	82%	87%	6%	5	118,807	6,297
Total						8,470,191	448,920						5,302,477	281,031

Unit Size (MMBTU/hr)	Unit Cost for Size	Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
50	$ 1,500,000	0.30	20	0.301586885	$ 7.69	0.053	8760

	Replace Low Efficiency Process Heaters				Replace Medium Efficiency Process Heaters			
Sub-Sector	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 3,000,000	$ 71,154,538	$ 61,883,421	$ 22	$ 3,000,000	$ 71,154,538	$ 38,740,028	$ 121
Food	$ 600,000	$ 1,531,993	$ 1,184,339	$ 43	$ 600,000	$ 1,531,993	$ 741,416	$ 155
Iron and Steal	$ 1,200,000	$ 734,746	$ 568,010	$ 43	$ 1,200,000	$ 734,746	$ 355,584	$ 155
Chemical	$ 1,500,000	$ 1,775,648	$ 1,458,495	$ 32	$ 1,500,000	$ 1,775,648	$ 913,042	$ 137
Total		$ 75,196,926	$ 65,094,266			$ 75,196,926	$ 40,750,069	

[1] Uses the widest range of boiler efficiencies

Sub-Sector	Assumptions					Calculations			
	Percent of Fuel Used By Process Heat	Process Heater Size Range (MMBTU/hr)	Process Heater Size (staff estimate) (MMBTU/hr)	Process Heater Efficiency (staff estimate[1]) (percent)	Capacity (staff estimate) (percent)	Number of Total Process Heaters	Average Process Heater Fuel Use (MMBTU)	2008 Emissions ($MTCO_2e$)	Number of Entities
Petroleum	63%	>60	100	77-83	0.9	524	788,400	35,006,224	413,356,010
Food	26%	10-100	20	77-83	0.8	56	140,160	1,627,120	7,910,902
Iron and Steel	76%	10-100	40	77-83	0.85	13	297,840	263,693	3,794,077
Chemical	20%	10-100	50	77-83	0.9	25	394,200	2,557,335	9,742,154

Sub-Sector	Optimize Process Heater (Category 1)					Optimize Process Heater (Category 2)				
	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	34%	2%	177	2,786,020	147,659	40%	1%	212	1,671,612	88,595
Food	34%	2%	19	53,319	2,826	40%	1%	23	31,992	1,696
Iron and Steel	34%	2%	4	25,572	1,355	40%	1%	5	15,343	813
Chemical	34%	2%	8	65,662	3,480	40%	1%	10	39,397	2,088
Total				2,930,573	155,320				1,758,344	93,192

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity of Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Optimize Process Heater (Category 1)				Optimize Process Heater (Category 2)			
	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Price per Unit[2]	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 121,179	$ 6,457,228	$ 21,410,839	$ (101)	$ 181,768	$ 9,685,842	$ 12,846,503	$ (36)
Food	$ 21,543	$ 123,580	$ 409,766	$ (101)	$ 32,314	$ 185,370	$ 245,859	$ (36)
Iron and Steel	$ 45,779	$ 59,269	$ 196,524	$ (101)	$ 68,668	$ 88,904	$ 117,914	$ (36)
Chemical	$ 60,589	$ 152,187	$ 504,620	$ (101)	$ 90,884	$ 228,280	$ 302,772	$ (36)
Total		$ 6,792,264	$ 22,521,748			$ 10,188,396	$ 13,513,049	

[1] Uses the widest range of boiler efficiencies

[2] For Category 2, staff assumed a 50 percent greater cost than Category 1

	Assumptions					Calculations			
Sub-Sector	Percent of Fuel Use By Process Heat	Process Heater Size Range (MMBTU/hr)	Process Heater Size (staff estimate) (MMBTU/hr)	Process Heater Efficiency (staff estimate[1]) (percent)	Capacity (staff estimate) (percent)	Number of Total Process Heaters	Average Process Heater Fuel Use (MMBTU)	2008 Emissions ($MTCO_2e$)	Number of Entities
Petroleum	63%	>60	100	77-83	0.9	524	788,400	35,006,224	413,356,010
Food	26%	10-100	20	77-83	0.8	56	140,160	1,627,120	7,910,902
Iron and Steel	76%	10-100	40	77-83	0.85	13	297,840	263,693	3,794,077
Chemical	20%	10-100	50	77-83	0.9	25	394,200	2,557,335	9,742,154

	Recover Flue Gas Heat (Category 1)					Recover Flue Gas Heat (Category 2)				
Sub-Sector	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	15%	2.0%	79	1,240,068	65,724	18%	1.0%	94	744,041	39,434
Food	15%	3.5%	8	41,532	2,201	18%	1.8%	10	24,919	1,321
Iron and Steel	15%	3.5%	2	19,919	1,056	18%	1.8%	2	11,951	633
Chemical	15%	2.0%	4	29,226	1,549	18%	1.0%	4	17,536	929
Total				1,330,746	70,530				798,447	42,318

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

	Recover Flue Gas Heat (Category 1)				Recover Flue Gas Heat (Category 2)			
Sub-Sector	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 424,125	$ 10,059,480	$ 9,530,047	$ 8	$ 424,125	$ 10,059,480	$ 5,718,028	$ 110
Food	$ 131,950	$ 336,911	$ 319,179	$ 8	$ 131,950	$ 336,911	$ 191,508	$ 110
Iron and Steel	$ 280,394	$ 161,583	$ 153,079	$ 8	$ 280,394	$ 161,583	$ 91,847	$ 110
Chemical	$ 212,063	$ 237,086	$ 224,608	$ 8	$ 212,063	$ 237,086	$ 134,765	$ 110
Total		$ 10,795,060	$ 10,226,913			$ 10,795,060	$ 6,136,148	

[1] Uses the widest range of boiler efficiencies

Sub-Sector	Assumptions: Percent of Fuel Use by Process Heat	Process Heater Size Range (MMBTU/hr)	Process Heater Size (staff estimate (MBTU/hr)	Process Heater Efficiency (staff estimate[1]) (percent)	Capacity (staff estimate) (percent)	Calculations: Number of Total Process Heaters	Average Process Heater Fuel Use (MMBTU)	2008 Emissions ($MTCO_2e$)	Number of Entities
Petroleum	63%	>60	100	77-83	0.9	524	788,400	35,006,224	413,356,010
Food	26%	10-100	20	77-83	0.8	56	140,160	1,627,120	7,910,902
Iron and Steel	76%	10-100	40	77-83	0.85	13	297,840	263,693	3,794,077
Chemical	20%	10-100	50	77-83	0.9	25	394,200	2,557,335	9,742,154

Sub-Sector	Replace Refractory Brick (Category 1): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Replace Refractory Brick (Category 2): Feasibility (percent)	Efficiency Increase (percent)	Number of Units	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	4.0%	1.0%	21	165,342	8,763	4.8%	0.5%	25	99,205	5,258
Food	4.0%	1.0%	2	3,164	168	4.8%	0.5%	3	1,899	101
Iron and Steel	4.0%	1.0%	1	1,518	80	4.8%	0.5%	1	911	48
Chemical	4.0%	1.0%	1	3,897	207	4.8%	0.5%	1	2,338	124
Total				173,921	9,218				104,353	5,531

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

Sub-Sector	Replace Refractory Brick (Category 1): Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Replace Refractory Brick (Category 2): Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 72,707	$ 459,862	$ 1,270,673	$ (93)	$ 72,707	$ 459,862	$ 762,404	$ (58)
Food	$ 12,926	$ 8,801	$ 24,318	$ (93)	$ 12,926	$ 8,801	$ 14,591	$ (58)
Iron and Steel	$ 27,467	$ 4,221	$ 11,663	$ (93)	$ 27,467	$ 4,221	$ 6,998	$ (58)
Chemical	$ 36,354	$ 10,838	$ 29,948	$ (93)	$ 36,354	$ 10,838	$ 17,969	$ (58)
Total		$ 483,722	$ 1,336,602			$ 483,722	$ 801,961	

[1] Uses the widest range of boiler efficiencies

Sub-Sector	Assumption: Percent of Fuel Used By Process Heat	Calculations: 2008 Emissions ($MTCO_2e$)	Calculations: Number of Entities
Petroleum	63%	35,006,224	413,356,010
Food	26%	1,627,120	7,910,902
Iron and Steel	76%	263,693	3,794,077
Chemical	20%	2,557,335	9,742,154

	Insulation Maintenance (Category 1)				Insulation Maintenance (Category 2)			
Sub-Sector	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)	Feasibility (percent)	Efficiency Increase (percent)	Total Fuel Reduction (MMBTU)	GHG Reduction ($MTCO_2e$)
Petroleum	40%	3.5%	5,786,984	306,710	5%	7.5%	1,550,085	82,155
Food	40%	3.5%	110,753	5,870	5%	7.5%	29,666	1,572
Iron and Steel	40%	3.5%	53,117	2,815	5%	7.5%	14,228	754
Chemical	40%	3.5%	136,390	7,229	5%	7.5%	36,533	1,936
Total			6,087,244	322,624			1,630,512	86,417

Interest Rate	Years	Annuity Factor	2020 Price of Fuel ($/MMBTU)	Carbon Intensity Natural Gas ($MTCO_2e$/MMBTU)	Hours per Year
0.30	20	0.301586885	$ 7.69	0.053	8760

	Insulation Maintenance (Category 1)				Insulation Maintenance (Category 2)			
Sub-Sector	Total Capital Cost (2 Year Payback)	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)	Price per Unit	Total Annual Capital Cost	Total Annual Savings	Abatement Cost ($/$MTCO_2e$)
Petroleum	$ 88,947,104	$ 26,825,280	$ 44,473,552	$ (58)	$ 35,737,676	$ 10,778,014	$ 11,912,559	$ (14)
Food	$ 1,702,290	$ 513,388	$ 851,145	$ (58)	$ 683,956	$ 206,272	$ 227,985	$ (14)
Iron and Steel	$ 816,420	$ 246,222	$ 408,210	$ (58)	$ 328,026	$ 98,928	$ 109,342	$ (14)
Chemical	$ 2,096,344	$ 632,230	$ 1,048,172	$ (58)	$ 842,281	$ 254,021	$ 280,760	$ (14)
Total		$ 28,217,120	$ 46,781,079			$ 11,337,236	$ 12,530,646	

RESPONSES TO COMMENT LETTER #8
(Communities for a Better Environment – October 6, 2015)

8-1 The claim that additional cost-effective NOx emission reductions beyond what was analyzed in the PEA proposed project are available, achievable and necessary and that they should be included as an alternative in a recirculated PEA is addressed partially below and in more detail in Responses 8-2 and 8-3.

Two opportunities (e.g., during the 57-day public review and comment period of the NOP/IS and at the CEQA scoping meeting) were provided to commenters to suggest ways of crafting the various alternatives to be analyzed in the PEA. The SCAQMD received several suggestions for alternatives and none included the alternative suggested in this comment. This is why the Draft PEA does not contain an analysis of this suggested alternative.

Based on input from the public, stakeholders and other interested parties, SCAQMD staff crafted five alternatives that were included in the PEA and one of the five is the no project alternative (e.g., Alternative 4) as required by CEQA Guidelines §15126.6 (e). When considering and discussing alternatives to the proposed project, an EIR need not consider every conceivable alternative to a project but instead consider a reasonable range of potentially feasible alternatives that will foster informed decision making and public participation. [CEQA Guidelines 15126.6 (a)]. SCAQMD staff believes that the PEA contains a reasonable range of potentially feasible alternatives. Thus, as further explained in Responses 8-2 and 8-3, no additional alternatives are necessary or required and the Draft PEA does not need to be recirculated.

8-2 This comment suggests that there are other control measures (e.g., replacing low and medium efficiency boilers or heaters, optimizing boilers by reducing excess air, retrofitting feed water economizers, retrofitting air preheaters, etc.) that could be implemented to reduce the fuel usage in boilers and heaters, and as a consequence reduce greenhouse gases, and other co-pollutants such as NOx and CO. This comment is addressed in Response 8-3.

This comment also claims that there is a NOx emission reduction potential of 12 tpd from an average inventory of 13.1 tpd for the 2001-2002 and 2002-2003 time frame which could result in a remaining inventory of 1.1 tpd NOx (13.1 – 12 = 1.1 tpd). Finally, this comment suggests that the SCAQMD's current proposal of 0.96 tpd reductions for boilers and heaters was too low and much higher reductions could be achieved from the refinery boilers and heaters source category.

It appears that the commenter has misunderstood the emission inventory and emission reduction data that was presented in the Table 5.1 of the Staff Report. For clarification, the 13.1 tpd emission inventory and emission reduction data mentioned in the comment is specific to the refinery boilers and heaters source category. The data from Table 5.1 has been summarized in the following table.

	A	B	C	D = A – C
Equipment Source Category	**2011 NOx Emissions (tpd)**	**2023 NOx Emission Reductions Beyond 2000/2005 BARCT (tpd)**	**2023 NOx Emissions at 2015 BARCT (tpd)**	**NOx Emission Reductions from 2011 Baseline (tpd)**
Boilers/Heaters >110 mmbtu/hr	4.88	0.44	0.38	4.50
Boilers/Heaters >40-110 mmbtu/hr	2.00	0.50	0.47	1.53
Boilers/Heaters 20-40 mmbtu/hr	0.45	0.00	0.10	0.35
Boilers/Heaters <20 mmbtu/hr	0.06	0.00	0.02	0.04
TOTAL	**7.39**	**0.94**	**0.97**	**6.42**

Note: Data in Columns A, B and C are from Table 5.1 of Draft Staff Report, October 2015.

As shown in Column A, the total inventory of NOx emissions from the refinery boilers and heaters source category was approximately 7.4 tpd in 2011. The inventory for the refinery boilers and heaters source category was reduced by 5.7 tpd NOx (13.1 – 5.7 = 7.4 tpd) since the 2002-2003 time frame. The 0.94 tpd in Column B represents the *incremental* emission reductions that occurred from the 2000/2005 BARCT levels analysis to the 2015 BARCT levels analysis, and does not reflect the entire amount of emission reductions from the baseline. In actuality, the entire amount of emission reductions from the 2011 baseline is 6.42 tpd as shown in Column D. By counting from the 2002-2003 baseline, the full amount of NOx emission reductions would be 12.1 tpd (5.7 + 6.4 = 12.1 tpd), which is a value that is consistent with the commenter's estimate. Finally, as shown in Column C, the remaining NOx emissions inventory would be 0.97 tpd, which is lower than the remaining emissions inventory of 1.1 tpd that was proposed by the commenter. Because the commenter's recommendation would actually result in less NOx emission reductions when compared to the proposed project, SCAQMD staff believes that the current staff proposal for reducing NOx emissions from the refinery boilers and heaters source category represents the maximum level that is technically feasible and cost-effective for add-on controls.

8-3 This comment provides suggestions for achieving additional NOx reductions that entail modifying equipment to make fuel efficiency and other improvements and that the PEA should be revised to reflect these suggestions.

In the upcoming 2016 AQMP, staff will propose two preliminary control measure concepts (e.g., CMB-01 and ECC-02) to specifically explore any potential air pollution benefits that may occur as a result of improving maintenance and energy efficiency, and from applying other optimizing approaches in order to reduce greenhouse gases and provide co-benefits of NOx reductions. CMB-01 is a proposed control measure concept that will examine potential NOx and greenhouse gas emission reduction opportunities that may be achieved from commercial and multi-residential space and water heating. Similarly, proposed control measure concept ECC-02 will examine potential NOx and greenhouse gas emission reduction opportunities that may be achieved from implementing energy efficiency measures for existing residential and commercial buildings.

Because these concepts are preliminary in nature, staff believes that additional time, data, and input from the stakeholders and the public are needed in order to conduct this type of analysis. Further, the incorporation of the commenter's suggestions into the PEA for this project would be premature because the 2016 AQMP is currently under development and on a completely separate schedule from the proposed project. As the 2016 AQMP development process moves forward, a separate CEQA analysis of the effects of what is proposed for the 2016 AQMP will be conducted and presented as part of a Program EIR which will provide multiple opportunities for review and comment by the public, stakeholders, and other interested parties. Thus, SCAQMD staff disagrees that the PEA for this project needs to be revised to analyze the suggestions provided in this comment.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Socioeconomic Report For
Proposed Amendments to Regulation XX – Regional Clean Air Incentive Market (RECLAIM)
NOx RECLAIM

November 2015

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1. EXECUTIVE SUMMARY

A socioeconomic analysis has been conducted to assess the impacts of the proposed amendments to Regulation XX – RECLAIM. The same level of analysis has also been performed on the California Environmental Quality Act (CEQA) alternatives. A summary of the analysis and findings are presented below.

Key Elements of the Proposed Amendments	The proposed amendments would reduce (or "shave") 14 tons per day (tpd) of NOx RECLAIM Trading Credits (RTCs) by the year 2023, of which 4 tpd would occur in 2016, and the remaining 10 tpd would be distributed evenly over the period of 2018–2022 at the rate of 2 tpd per year. These reductions will help the region attain federal ozone and PM2.5 standards. The amount and distribution of the proposed shave was determined based on the Best Available Retrofit Control Technology (BARCT) analysis. A new level of BARCT is proposed for Fluid Catalytic Cracking Units (FCCUs), boilers/heaters >40 mmBtu/hr, gas turbines, coke calciners, and sulfur recovery and tail gas incinerators used in the refinery sector. For the non-refinery sector a new BARCT level is proposed for container glass melting furnaces, sodium silicate furnaces, metal melting furnaces >150 mmBtu/hr, gas turbines and Internal Combustion Engines (ICEs) not located on the outer continental shelf (OCS). The proposed NOx shave of 14 tpd would be distributed as a 66 percent shave for 9 refineries and investors, a 49 percent shave for 21 electricity generating facilities, a 49 percent shave for 26 non-major facilities, and no shave for the 219 remaining facilities. By 2023, it would result in 12.51 tpd of remaining RTCs (26.51 tpd – 14 tpd = 12.51 tpd). This amount is expected to sufficiently account for the needs of all RECLAIM facilities, including growth and a compliance margin.
Affected Facilities and Industries	The proposed amendments would affect the current RTC holdings for 56 out of 275 RECLAIM facilities. The 56 affected facilities would include 9 major refineries, 21 electricity generating facilities, and 26 other top emitting non-refinery facilities. The nine affected refineries belong to the sector of petroleum product manufacturing (NAICS 324), the 21 electricity generating facilities belong to the sector of utilities (NAICS 221), the remaining 26 facilities belong to the sectors of manufacturing (NAICS 31-33), mining, oil and gas exploration (NAICS 211), utilities (NAICS 221), amusement and recreation industries (NAICS 713), and a military facility. Facilities in the 219 group represent a range of industries, but are largely comprised of manufacturing (NAICS 31-33), mining, oil and gas

	exploration (NAICS 211), and utilities (NAICS 221) industries.
Assumptions for the Analysis	The proposed amendments are assumed to induce full BARCT installation by 2023 at the 9 refineries and 11 non-refinery facilities where the 2015 BARCT analysis identified cost-effective controls for their major NOx emission sources. This assumption is made to arrive at the most conservative (i.e., maximum) compliance cost estimates. In reality, the RECLAIM program affords facilities with compliance flexibility so that the actual costs may be lower if a facility identifies any other more cost-effective alternatives to remain in compliance, such as RTC purchases and operational changes. The 9 refineries currently have the following equipment/source categories that have BARCT determinations for the proposed rule amendments: FCCUs, Sulfur Recovery Units/Tail Gas Incinerators (SRU/TGUs), coke calciners, refinery boilers and heaters, and refinery gas turbines. In response to the proposed rule amendments, operators of these refineries are assumed to install Selective Catalytic Reduction (SCR) technology, UltraCat Dry Gas Scrubbers (DGS), and Low Temperature Oxidation (LoTOx^{TM}) with Wet Gas Scrubbers (WGS). The 11 non-refinery facilities currently have the following equipment/source categories that have BARCT determinations for the proposed rule amendments: container glass melting furnaces, glass melting furnace facilities, sodium silicate furnaces, metal heat treating furnaces rated >150 mmBtu/hour, stationary ICEs and non-electricity generating plant stationary gas turbines. In response to the proposed rule amendments, operators of these facilities are assumed to install SCR technology or UltraCat DGS. For the purpose of conducting a worst-case analysis, 34 SCR units and 1 UltraCat DGS are assumed to be installed at the 11 non-refinery affected facilities. It is possible that another UltraCat DGS may also be installed in lieu of 1 of the 34 SCR units. In total, the proposed rule amendments are assumed to result in the installation of the following new NOx air pollution control equipment: 116 SCRs, 8 LoTOx^{TM} with WGSs, 1 LoTOx^{TM} without WGS, and 3 UltraCat DGSs. The annualization factor used for capital costs is based on a discount rate of 1 or 4 percent and a 25-year equipment life for all control equipment including SCRs, UltraCat DGS, and LoTOx^{TM} technology.

Cost Impacts	Total compliance cost associated with control equipment installation by 9 refineries and 11 non-refinery facilities would range from $728 million to $1.1 billion in present worth values (expressed in 2014 dollars). Using the high-end cost estimates, the annualized compliance cost is estimated to be approximately $70 million when evaluated at a 4 percent discount rate, or $60 million when evaluated at a 1 percent discount rate from year 2022 onwards when all controls are assumed to have been installed. More than 73 percent of the annualized compliance cost is expected to occur in the refinery sector, and more than 43 percent of the sector's annualized compliance cost would be associated with FCCU installation. Among the non-refinery sectors, gas turbines would account for more than 60 percent of the sector's annualized compliance cost. It should be noted that these cost estimates do not consider the possibility that these 20 facilities could potentially sell surplus NOx RTCs, if any, resulting from control installation. This would then offset some of the control installation costs. The proposed shave could potentially affect facilities with no identified cost-effective controls in two ways. First, 36 of these facilities would be subject to the proposed shave, and some of them would need to buy additional NOx RTCs to reconcile actual emissions. Second, all facilities could potentially pay a higher price for NOx RTCs that they purchase each year for compliance. Additionally, higher NOx RTC prices could be potentially induced by the opt-out of any electricity generating facilities that regularly sell their surplus discrete credits or by removing from the market NOx RTCs resulting from the shut-down of RECLAIM facilities. Furthermore, under the proposed amendments, the 12-month rolling average price trigger would be raised to $22,500 per ton (discrete credits), thus potentially allowing NOx RTC prices to increase further before non-tradable/non-usable NOx RTCs are converted to tradable/usable NOx RTCs; however, the proposed addition of a 3-month rolling average price trigger of $35,000 per ton (discrete credits) would institute another safeguard. Total incremental compliance cost (expressed in 2014 dollars) associated with RTC purchases over the course of 25 years is estimated to range from $19 million—if discrete NOx RTC prices remain the same—to $500 million—if the average annual discrete NOx RTC prices increase to $22,499/ton for a total of 25 years and none of the affected facilities pursue any other more cost-effective compliance options.
Job Impacts	Assuming that the proposed amendments would induce full BARCT installation by 2023 and the 9 refineries and 11 non-refinery facilities would incur the high-end estimated costs, it is projected that about 20 jobs on the net would be created on an annual average between 2018 and 2035, and about 140 net jobs would be foregone when the

	analysis horizon is extended to 2043. (Note that jobs foregone may include either losses of existing jobs or projected additional jobs not created.) The difference is because the majority of jobs, mostly in the construction sector, would be created at the beginning of the analysis period (2018-2022) when control installation is assumed to take place. Despite having a large share of the total compliance cost, the refinery industry is projected to have fewer jobs forgone relative to other industries with similar magnitude of cost impact due to the fact that the industry is the most capital-intensive. As such, less labor would be required to produce the same amount of products or services. Note that the projected job impact would be more positive (i.e., fewer jobs foregone) if facilities sell any surplus NOx RTCs that result from installing control equipment, to offset control installation costs. Regarding the incremental compliance cost that could be potentially incurred by the rest of NOx RECLAIM facilities, the associated job impacts have been estimated under various scenarios of discrete NOx RTC prices. If prices remain the same, little job impact is expected due to the proposed amendments. If the average annual discrete NOx RTC prices increase to $22,499/ton and none of the affected facilities pursue any other more cost-effective compliance options, then about 40 jobs on the net would be foregone annually between 2023 and 2035. However, this latter price scenario is unlikely to occur, particularly if the 9 refineries and 11 non-refinery facilities install identified cost-effective controls, which would then either decrease the market demand or increase the market supply of NOx RTCs by these facilities.
Impact of CEQA Alternatives	Five alternatives to the proposed amendments were developed for the CEQA analysis associated with this proposal: Alternative 1 (Across the Board), Alternative 2 (Most Stringent), Alternative 3 (Industry Approach), Alternative 4 (No Project), and Alternative 5 (Weighted by BARCT Reduction Contribution for all Facilities and Investors). After further analysis, staff determined Alternatives 3 and 4 do not comply with state law. Regarding cost-effective control installation, the proposed rule amendments have the highest cost but the second to highest positive job impact, due to increased labor demand for the full, instead of partial, installation of control equipment. Alternative 4 would maintain the status quo and serves as a benchmark against which other alternatives were evaluated; however, it does not comply with state law. Of the four remaining alternatives, Alternative 3, which also does not comply with state law, has the lowest annualized cost ($9.40 million) because it is expected to induce the lowest number of control equipment to be installed; for the same reason, however, it

	would not create as many jobs and would result in an average of 30 jobs foregone on an annual average. Alternatives 1 and 2 would cost less than the proposed amendments, yet would experience more negative job impacts (approximately 80 jobs forgone on an annual average basis). This is due to less control equipment installation spending in the refinery sector relative to the 11 non-refinery facilities and would result in negative net job impacts. For the incremental costs associated with NOx RTC purchases that could potentially be incurred by some of the facilities without identified cost-effective controls, Alternative 2 has the highest estimated costs (up to $31 million in total), as it would result in the largest amount of NOx RTC shave. In terms of job impacts, all CEQA alternatives except Alternative 4 (No Project) would result in a more negative job impact—up to about 60 jobs foregone on an average annual basis if the average annual discrete NOx RTC prices increase to $22,499/ton and none of the affected facilities pursue any other more cost-effective compliance options—than the proposed amendments. This is mainly because, unlike the proposed amendments, Alternatives 1, 2, 3 and 5 would not exempt from the shave the 219 facilities that tend to be smaller and use more labor-intensive production technologies than, for example, those used by the refineries.
Health Benefits	The South Coast Air Basin is one of only two "extreme" non-attainment areas in the nation that have not reached the federal 8-hour ozone standard. The amount of pollutants produced by modern urban life and industrial activities, combined with Southern California's year- round sunny weather, all contribute to the high concentrations of ground-level ozone in the area. Ozone exposure can cause immediate, adverse effects on the respiratory system. Long-term impacts of frequent exposure to ozone may lead to permanent lung damage and increase the risk of premature death. In addition, the South Coast Air Basin remains a non-attainment area for the federal 24-hour and annual PM2.5 standards. Exposure to high levels of PM2.5 have been shown to cause and aggravate cardiopulmonary illnesses. NOx is a precursor of PM2.5. These outcomes result in increased absences from school and work, hospitalization, and other medical expenses. Exposure to PM2.5 is associated with premature deaths. According to recent estimates by the California Air Resources Board, elevated ambient PM2.5 levels result in approximately 4,100 premature deaths annually in the South Coast Air Basin.

Costs of Command and Control Compared to RECLAIM	RECLAIM allows facilities to use the least costly option to remain in compliance. Unlike command-and-control rules where every source has to be controlled to the same emission standard, RECLAIM facilities can pursue operational changes or purchase RTCs from investors or other facilities with surplus credits in lieu of upgrading existing control equipment, installing new control equipment or making other changes. Therefore, by design, total costs to install controls under the RECLAIM program since its adoption will always be equal to or less than total costs under command and control. The stream of cost-savings for any RECLAIM facility would only be reduced when, at a point in time, it becomes more economical for the facility to install the control equipment that would have been required under command-and-control. However, the future cost-savings may not be completely eliminated by control installation as long as the facility is able to sell surplus RTCs to offset some of the control installation costs. For example, following the 2005 NOx RECLAIM amendments, none of the 51 SCRs identified in the BARCT analysis for refineries have been installed because of RECLAIM, and 4 SCRs were installed only due to orders for abatement. As a result, refineries have saved approximately $205 million since 2007 by delaying installation of 47 SCRs. The cost-savings would continue to accumulate as long as refineries are able to further delay the installation of SCRs and still remain in compliance under RECLAIM. This continuous stream of cost-savings would only be reduced or even ceased if the currently proposed shave could eventually induce at least some of the 47 SCRs to be installed.

2. INTRODUCTION

RECLAIM allows facilities to use the most cost-effective approach to meet their obligation to surrender RTCs to match their quarterly and annual emissions, while helping the region attain clean air goals. This is possible, because unlike command-and-control regulations where every source is controlled to the same emission standard, a RECLAIM facility with more emissions than its actual RTC holdings has the option to install pollution control equipment, change operations, or purchase additional RTCs to offset its total emissions. Facilities are expected to choose whichever option is more economical for their business.

The proposed rule amendments consist of applying a shave to investors and to the facilities holding the top 90 percent of NOx RTCs, as weighted by a Best Available Retrofit Control Technology (BARCT) reduction contribution to achieve an overall reduction of 14 tons of NOx per day by 2023 according to the following implementation schedule as summarized below:

Table 1: Implementation Schedule for NOx RTC Reductions

Implementation Year	Amount of NOx RTC Reductions (tons/day)
2016	4
2018	2
2019	2
2020	2
2021	2
2022	2
TOTAL	**14**

The proposed shave of 14 tpd of NOx RTCs for the top 56 emitters is expected to assist in achieving clean air goals and meeting the requirements of state law by inducing the 20 facilities (9 refineries and 11 non-refineries[1]) to reduce actual emissions.

At the beginning of the RECLAIM program in 1994, a total of 392 NOx facilities were allocated RTC holdings at no cost. As a net outcome of facility shutdowns and new facilities joining the universe, there were 275 facilities in the NOx program in 2013, with a total of 26.51 tpd RTC holdings. Over the past decade, facilities have met their emission-reduction obligations under RECLAIM by purchasing unused “excess” RTCs and, only to a lesser extent, by reducing actual NOx emissions. Some of these unused “excess” credits can be attributed to facility shutdowns and the subsequent selling of credits. Regardless of why there are excess credits, their existence exerts downward pressure on the RTC market price and may have dis-incentivized RECLAIM facilities to install many of the already identified cost-effective control measures. For example, in the 2005 NOx RECLAIM amendments, the BARCT analysis included the potential installation of 51 SCR units at refineries. However, not one has been installed due to the RECLAIM program (4 SCR units were installed only due to orders for abatement).

[1] Two of the 11 non-refineries would not have their NOx RTC holdings shaved because they are not among the top 90 percent holders of NOx RTCs.

According to staff analysis of the RECLAIM transaction records, many of the unused RTCs were sold, as Infinite-Year-Blocks (IYBs), to operating RECLAIM facilities by some of the now-closed facilities prior to facility closure. These excess RTCs have been artificially depressing RTC prices and have induced RECLAIM facilities to delay the installation of cost-effective controls. A case in point is the 2005 NOx RECLAIM amendments. Despite 7.7 tpd of NOx RTC shave from the 2005 amendments being implemented over the period of 2007-2011, only 4 tpd of actual NOx emission reductions had occurred by the end of the 2012 Compliance Year. Some of the 4 tpd of actual reductions came from operational changes at refineries, which chose to run gas turbines instead of higher-emitting boilers at various points in time. However, just less than two thirds of the 4 tpd actual reductions were due to facility shut-downs (Table 2) and not measures taken to reduce actual emissions by facilities in the program. This outcome is not optimal for achieving clean air goals in the Basin.

Table 2: RECLAIM Facility Shutdowns from 2006 to 2012

Facility	**2006 Audited NOx emissions (lbs)**	**2012 Audited NOx emissions (lbs)**	**Difference (tpd)**
A	1,582,879	9,372	2.16
B	136,876	655	0.19
C	125,778	0	0.17
D	80,669	0	0.11
Total			**2.62**

Excess RTC holdings have ranged between 5.45-8.41 tpd over the past five years. Removing at least a portion of these excess credits from the market would relieve the downward pressure on the RTC market price and would be more likely to make control equipment installation a more cost-effective option than purchasing RTCs, particularly for the 20 facilities with newly identified control equipment.

In accordance with the requirements of the California Health and Safety Code (H&SC), SCAQMD staff conducted a BARCT assessment of the NOx RECLAIM program to: 1) assess advancements in control technology; 2) to ensure that RECLAIM facilities achieve the same emissions reductions as the implementation of BARCT; 3) to ensure that emission reductions from the NOx RECLAIM program contribute towards achieving the federal National Ambient Air Quality Standards (NAAQS); and, 4) to assure that the participating facilities will continue to achieve emission reductions as expeditiously as possible to carry out the commitments in the 2012 Air Quality Management Plan (AQMP).

Based on the BARCT analysis[2], a new level of BARCT is proposed for Fluid Catalytic Cracking

[2] Except for electricity generating facilities, the proposed RTC shave reduction will be based on compliance year 2011 activity levels for all other affected facilities. The 2012 activity levels will be used for RTC reductions from electricity generating facilities because this activity level better represents this sector's energy consumption.

Units (FCCUs), boilers/heaters >40 mmBtu/hr, gas turbines, coke calciners, and sulfur recovery and tail gas incinerators used in the refinery sector. For the non-refinery sector (except electricity generating plants), a new BARCT level is proposed for container glass melting furnaces, sodium silicate furnaces, metal melting furnaces >150 mmBtu/hr, gas turbines and ICEs not located on the outer continental shelf (OCS).

To realize the emission reduction potential of 2015 BARCT and help the Basin achieve the PM2.5 standards by 2019 and 2024 and the ozone standards by 2024 and 2032, staff proposes reductions (or a "shave") of NOx RECLAIM Trading Credits (RTCs) by a total of 14 tpd to be implemented over a seven-year period from 2016 to 2022. This number includes shaving unused RTCs as well as assuming programmatic BARCT equivalency. See the Staff Report for the rationale for this approach. Currently, there are 275 RECLAIM facilities holding 26.51 tpd of NOx RTCs in total, among which the refinery sector holds 51 percent of the RTCs, electricity generating plants 21 percent, investors 4 percent and other RECLAIM facilities 24 percent. The proposed shave of 14 tpd would result in 12.51 tpd of remaining RTCs (26.51 tpd – 14 tpd = 12.51 tpd). This amount is expected to sufficiently account for:

- The projected 2023 emissions by RECLAIM facilities at the proposed 2015 BARCT levels[3], which would be 10.23 tpd (2.76 tpd for the refinery sector plus 7.47 tpd for the non-refinery sector).
- A 10 percent compliance margin that has been added to the projected 2023 emissions
- An adjustment to account for other uncertainties (e.g. uncertainties in BARCT analysis, and base year activity level adjustments)

Under the proposed amendments, the 14 tpd of NOx RTC reductions would be distributed as a 66 percent shave for 9 refineries and investors, a 49 percent shave for 21 electricity generating facilities, a 49 percent shave for 26 non-major facilities, and no shave for the 219 remaining facilities. As a result, the shave would directly affect a total of 56 facilities plus investors that together hold 90 percent of the 26.51 tpd of the NOx RTCs. Other facilities that would not be shaved may also be indirectly impacted by potential changes in RTC price due to the proposed NOx RTC reductions.

3. METHODOLOGY FOR SOCIOECONOMIC ASSESSMENT

For the purpose of the socioeconomic analysis of the proposed amendments and CEQA alternatives for the NOx RECLAIM program, staff has assumed three compliance cost categories: (1) costs of control equipment implementation for 9 refineries and 11 non- refineries that would be shaved,[4] assuming all control equipment identified in the 2015 BARCT analysis would be

[3] To account for projected industry growth, the growth factor assumptions are: 1) 1.0 for the refinery sector; 2) 0.89 for electricity generating facilities; and 3) 1.1 -1.3 for the non-refinery sector. These growth factors are based on those in the Draft Final Staff Report, which are based on growth factors for point sources in 2012 AQMP made by SCAG. The only exception is for EGFs, whose growth factors were based on the 2014 Gas Fuel Report.

[4] Note that the current socioeconomic analysis uses the high-end cost estimate specified in the Revised Draft Staff Report. Cost estimates based on Norton Engineering Consultants (NEC)'s analysis for the refinery FCCUs lie between

installed by 2023 in lieu of other compliance options such as RTC purchases or operational changes, (2) incremental costs for a fraction of the remaining 36[5] shaved facilities to purchase RTCs to remain in compliance, due to both additional credits potentially needed and any potential increase in RTC price, and (3) incremental costs of purchasing RTCs at potentially higher prices for a fraction of the 219 non-shaved facilities that historically purchase credits from the market to reconcile actual emissions with RTCs. The costs associated with control equipment implementation are described in the cost section and then used as inputs to simulate and assess the regional macroeconomic impact of the proposed amendments and CEQA alternatives. The costs and job impacts resulting from the shave for a fraction of the 36 facilities and the 219 non-shaved facilities are discussed further in the Market Analysis section.

4. REGULATORY HISTORY

In 1993, SCAQMD adopted an emissions trading program (RECLAIM) for stationary sources as a market incentive system to cost-effectively achieve emission reductions. RECLAIM establishes facility mass emission limits for NOx and SOx and allows sources the flexibility to achieve regional prescribed emission reduction targets through process changes, installation of control equipment, and emissions trading. H&SC §39616 (c)(1) and (c)(4) required that findings be made that a market-based incentive program would result in "equivalent or less cost" and "not result in greater loss of jobs or more significant shifts from higher to lower skilled jobs than" the counterpart command-and-control regulation, at the time of adoption and 5 years later. Staff does not expect a shift from high- pay to low-pay jobs as a result of the proposed rule amendments.

A socioeconomic analysis of RECLAIM was conducted at the time of its adoption. The cost of RECLAIM was estimated to be $80.8 million annually, on average, compared with the $138.7 million cost of the corresponding command-and-control system (which included rules and control measures in the 1991 AQMP that were subsumed by RECLAIM). RECLAIM was predicted to result in an average of 866 jobs forgone annually, compared with 2,013 jobs forgone under the command-and-control system. Based on the five occupational categories from the lowest-paid to the highest-paid, RECLAIM was projected to result in increased employment opportunities for nearly every category relative to the command-and-control system.

Until the year 2000, prices of NOx RTCs were relatively stable between $1,500 and $3,000 an annual ton per day. In 2000, prices of NOx RTCs rose very quickly to over $45,000 a ton due to the increased demand for RTCs from electricity generating plants in response to the deregulated electricity generation market and limited installation of air pollution controls. In order to address the issues in the RECLAIM market, the Board removed large electricity generating plants from the market in May 2001. These electricity generating plants were required to file compliance plans for the installation of BARCT and restrictions were placed on the use and trade of their NOx RTCs. Other amendments to RECLAIM in 2001 included filing of compliance plans and forecast reports by large (at least 50 tons of NOx emissions) and medium (between 25 and 50 tons of NOx emissions) non-electricity generating facilities and the access to RECLAIM Air Quality Investment Program (AQIP), Mitigation Fee Program, and state Emission Credit Bank by

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the low- and high-end of the range provided in the staff report.

[5] Inland Empire Energy Center and General Electric are considered as one facility, as the latter serves as a holding account for the former.

designated facilities. At the time, the Board also adopted several mobile and area source emission reduction credit rules whose credits could be used by RECLAIM facilities to comply with their allocations.

The annualized cost for installing controls on electricity generating facilities was projected to be $9 million. The annualized cost for the level 1 controls (known technologies at the time) on non-electricity generating facilities was estimated to be $26 million.[6] It was projected that 640 jobs would be forgone annually from the proposed controls, filing of compliance plans and forecast reports, the access to a reserve of NOx emission reductions, and the creation of mobile and area source credit rules.

In 2005, Regulation XX – RECLAIM was amended to achieve additional NOx reductions pursuant to the 2003 AQMP Control Measure #2003CMB-10. The proposed amendments also addressed requirements for demonstrating BARCT equivalency in accordance with H&SC §40440. In addition, trading restrictions for electricity generating producing facilities were removed.

4.1 Legislative Mandates

The socioeconomic assessments at the SCAQMD have evolved over time to reflect the benefits and costs of regulations. The legal mandates directly related to the assessment of the proposed rule include the SCAQMD Governing Board resolutions and various sections of the H&SC.

4.2 SCAQMD Governing Board Resolutions

On March 17, 1989 the SCAQMD Governing Board adopted a resolution that calls for an economic analysis of regulatory impacts that includes the following elements:

- Affected industries
- Range of control costs
- Cost effectiveness
- Public health benefits

On October 14, 1994, the Board passed a resolution which directed staff to address whether the rules or amendments brought to the Board for adoption are in the order of cost effectiveness as defined in the AQMP. The intent was to bring forth those rules that are most cost-effective first.

4.3 Health & Safety Code Requirements

The state legislature adopted legislation that reinforces and expands the Governing Board resolutions for socioeconomic assessments. H&SC §40440.8(a) and (b), which became effective on January 1, 1991, require that a socioeconomic analysis be prepared for any proposed rule or rule amendment that "will significantly affect air quality or emissions limitations." Specifically, the scope of the analysis should include:

[6] Specifically, Level 1 technologies included selective catalytic reduction (SCR) and low-NOx burner (LNB) controls on non-electricity generating turbines (SCR), internal combustion engines (SCR), boilers (LNB), heaters (ultra LNB), dryers (ultra LNB or LNB), ovens (LNB), furnaces (LNB or oxy-fuel), and afterburners (LNB).

- Type of affected industries
- Impact on employment and the economy of the district
- Emission reduction potential
- Necessity of adopting, amending or repealing the rule in order to attain state and federal ambient air quality standards
- Availability and cost effectiveness of alternatives to the rule

Additionally, the SCAQMD is required to actively consider the socioeconomic impacts of regulations and make a good faith effort to minimize adverse socioeconomic impacts. H&SC §40728.5, which became effective on January 1, 1992, requires the SCAQMD to:

- Examine the type of industries affected, including small businesses; and
- Consider socioeconomic impacts in rule adoption

Finally, H&SC §40920.6, which became effective on January 1, 1996, requires that incremental cost effectiveness be performed for a proposed rule or amendment that imposes BARCT or "all feasible measures" requirements relating to ozone, carbon monoxide (CO), oxides of sulfur (SOx), oxides of nitrogen (NOx), and their precursors.

Furthermore, H&SC §39616 (c)(1) and (c)(4) requires that at adoption, a market-based incentive program result in equivalent or less cost and not result in greater job losses or more significant shifts from high- to low-skilled jobs as compared with command-and- control measures. This finding was made in 1993 when RECLAIM was adopted and in 2000 when the findings were ratified.

Finally, H&SC §40440.5 requires that social, economic, and public health analyses of proposed rules be available to the public by at least 30 days prior to the hearing.

5. SHORT-TERM/LONG-TERM ECONOMIC OUTLOOK

According to the Wells Fargo Economic Forecast released on June 3, 2015, "California's economy should continue to outperform the national average over the next couple of years, led by continued gains in the state's technology sector and stronger growth in residential and commercial construction." Despite a whole host of challenges ranging from the drought to labor strikes at its major ports, California's economy has maintained strong momentum through the first part of 2015.

According to the 2015-2016 Economic Forecast and Industry Outlook from Los Angeles Economic Development Corporation (LAEDC), Southern California will continue employment gains and experience a decline in local unemployment rates. Southern California's leading industries are:

- Healthcare and Social Assistance
- Construction
- Professional, Scientific and Technical Services

- Administrative Support
- Waste Services

The lagging industries are other services, nondurable goods manufacturing, and financial activities.[7]

The economy of the four counties falling under the SCAQMD's jurisdiction is comprised of a large non-manufacturing sector and a much smaller manufacturing sector. The service sector and the retail and wholesale trade sector combined constituted over 52 percent of the region's employment in 2014 Regional Economic Models (REMI, 2014). Most of the affected RECLAIM facilities belong to manufacturing and utilities sectors. For these sectors, the California State University, Fullerton (CSUF) projected steady and positive employment growth in 2015 and 2016 for the counties of Orange, Riverside, and San Bernardino. Table 3 presents the projected annual percentage employment growth by sector for 2015 and 2016.

Table 3: Annual Percentage Employment Growth by Sector

Sector	Los Angeles			Orange			Riverside & San Bernardino			Southern California		
	2014	2015f	2016f	2014	2015f	2016f	2014	2015f	2016f	2014	2015f	2016f
Mining and logging	3.4%	-1.4%	-0.4%	1.1%	3.2%	2.8%	0.9%	6.0%	3.0%	7.0%	1.1%	-0.6%
Construction	10.5%	7.7%	5.7%	9.6%	6.4%	9.1%	5.3%	0.5%	4.6%	8.6%	5.6%	6.6%
Total Manufacturing	-4.1%	1.1%	-1.0%	-0.3%	2.1%	2.1%	1.6%	10.8%	6.7%	-2.2%	2.9%	1.0%
Durable Manufacturing	-2.1%	5.2%	-0.7%	0.9%	2.6%	2.3%	2.3%	13.8%	8.3%	-0.5%	5.8%	1.7%
Nondurable Manufacturing	-6.6%	-4.3%	-1.6%	-3.5%	0.9%	1.5%	0.4%	4.9%	3.3%	-4.8%	-1.9%	-0.2%
Transportation, Commun. & Utilities	2.2%	4.0%	3.3%	1.0%	1.4%	1.3%	3.8%	4.0%	4.6%	2.3%	3.5%	3.2%
Transportation, Warehousing & Utilit.	0.2%	4.3%	3.6%	1.2%	2.6%	2.9%	3.4%	3.9%	5.3%	1.0%	3.9%	3.9%
Wholesale Trade	3.3%	4.5%	2.7%	1.0%	0.7%	0.3%	3.6%	3.3%	3.3%	2.9%	3.4%	2.3%
Retail Trade	0.7%	4.3%	2.4%	-2.9%	-0.7%	-0.5%	2.2%	2.2%	-2.7%	-0.4%	2.2%	0.6%
Finance, Activities	2.7%	2.2%	2.5%	1.9%	1.9%	2.0%	3.7%	3.9%	4.5%	2.7%	2.4%	2.7%
Services	0.4%	1.8%	0.9%	1.2%	0.2%	0.3%	1.9%	1.8%	2.1%	0.8%	1.4%	1.1%
Total Government	2.3%	2.3%	2.3%	2.0%	2.2%	2.4%	3.7%	4.2%	4.7%	2.5%	2.6%	2.7%
Total Employment	3.4%	-1.4%	-0.4%	1.1%	3.2%	2.8%	0.9%	6.0%	3.0%	7.0%	1.1%	-0.6%

Note: "f" means forecast. Source: California State University, Fullerton
Source: http://business.fullerton.edu/Center/EconomicAnalysisAndForecasting/#Default.

In addition, the CSUF forecast projects lower unemployment rates in 2015 and 2016 for all the four counties and, Southern California as a whole. Table 4 presents the annual percentage change in unemployment. (CSUF 2015 Economic Forecast).

[7] http://laedc.org/2015/02/18/2015-2016-economic-forecast-published/.

Table 4: Annual Percentage Unemployment Rate Outlook

	2012	2013	2014	2015F	2016F
Southern California	10.2%	8.6%	7.4%	6.9%	6.5%
Los Angeles	10.9%	9.9%	8.7%	7.6%	7.0%
Orange County	7.6%	6.2%	5.3%	4.8%	4.5%
Riverside & San Bernardino	12.0%	10.2%	8.8%	8.4%	8.3%

Source: CSUF 2015 Economic Forecast.

For the long-term economic outlook, all sectors of the local economy, except manufacturing, will experience a positive job growth.[8] The long-term growth is robust in construction, mining, transportation, and utilities sectors. The manufacturing sector is projected to incur a modest negative job growth from 2012-2022. Please see Appendix A for 10-year industry employment projections for the 4-county area.

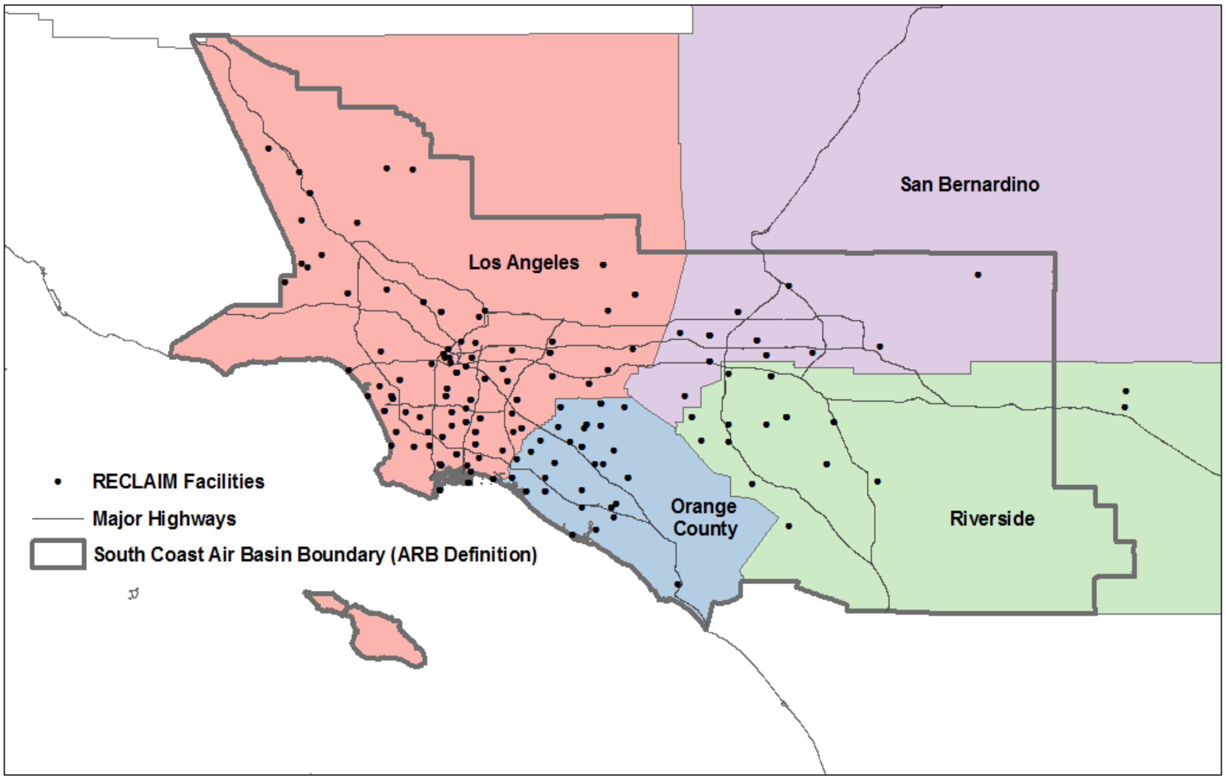
6. AFFECTED FACILITIES

The RECLAIM universe of facilities evolves due to shutdowns and the entry of new facilities. The RECLAIM program started with 392 NOx facilities in 1994 when RECLAIM went into effect. By the end of compliance year 2013, there were about 275 facilities in the NOx RECLAIM universe. Most of the RECLAIM facilities are relatively large emitting businesses (greater than 4 tons of NOx) with respect to their cohort in the same industry. These facilities are spread across all industries in the four-county economy. Of the 275 facilities, 66 percent were in Los Angeles County, 18 percent in Orange County, and 8 percent in both Riverside and San Bernardino Counties. Figure 1 shows the location of these facilities within the SCAQMD jurisdiction.[9]

[8] http://www.labormarketinfo.edd.ca.gov/data/employment-projections.html.

[9] While two facilities located in Desert Hot Springs fall outside the South Coast Air Basin Boundary as defined by the California Air Resources Board, Desert Hot Springs falls within the SCAQMD's jurisdiction for Riverside County. For more information see: http://www.aqmd.gov/home/about/jurisdiction.

Figure 1: Location of RECLAIM Facilities as of 2013



For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will only directly affect 56 facilities plus the investors that currently hold 90 percent of the NOx RTC credits. Out of the 56 facilities, 76 percent are in Los Angeles County, 4 percent in Orange County, 9 percent in Riverside County, and 11 percent in San Bernardino County.

They include 9 major refineries, 21 electricity generating facilities, and 26 other top-emitting non-refinery facilities. The 9 affected refineries belong to the sector of petroleum product manufacturing (NAICS 324), the 21 electricity generating facilities belong to the sector of utilities (NAICS 221), the remaining 26 facilities belong to the sectors of manufacturing (NAICS 31-33), mining, oil and gas exploration (NAICS 211), utilities (NAICS 221), amusement and recreation industries (NAICS 713), and a military facility.

For the remaining 219 facilities, no NOx RTC shave is proposed. Facilities in this group represent a range of industries, but are largely comprised of manufacturing (NAICS 31-33), mining, oil and gas exploration (NAICS 211), and utilities (NAICS 221) industries. Cost impacts on these facilities individually are expected to be small (if not zero). Any cost impacts that could potentially occur would be the result of any NOx RTC price increases due to the proposed amendments, and they are expected to be proportional to the amount of NOx RTCs currently needing to be purchased by these facilities.

6.1 Small Business

The SCAQMD defines a "small business" in Rule 102 for purposes of fees as one which employs 10 or fewer persons and which earns less than $500,000 in gross annual receipts. The SCAQMD also defines “small business” for the purpose of qualifying for access to services from the SCAQMD’s Small Business Assistance Office (SBAO) as a business with an annual receipt of $5 million or less, or with 100 or fewer employees. In addition to the SCAQMD's definition of a small business, the federal Small Business Administration (SBA) and the federal 1990 Clean Air Act Amendments (1990 CAAA) also provide definitions of a small business.

The 1990 CAAA classifies a business as a "small business stationary source" if it: (1) employs 100 or fewer employees, (2) does not emit more than 10 tons per year of either VOC or NOx, and (3) is a small business as defined by SBA. The SBA definitions of small businesses vary by six-digit NAICS codes. In general terms, a small business must have no more than 500 employees for most manufacturing and mining industries, and no more than $7 million in average annual receipts for most nonmanufacturing industries. For instance, the sector of petroleum refineries (NAICS 324110) has 1,500 employees as the threshold below which a business is considered small. The sector of utilities (NAICS 221111) has 500 to 1,000 employees as a threshold and non-metallic mineral products (NAICS 327213) which includes glass plants, has fewer than 750 employees as a threshold below which a business is considered small.

The 2015 Dun and Bradstreet data includes employment or gross revenue information for about half of the 275 facilities in the RECLAIM universe. According to the SCAQMD (Rule 102) definition of a small business, 11 facilities would be classified as small businesses. Under the 1990 CAAA definition, 26 facilities are considered small businesses. Based on SBA’s definition of a small business, 85 facilities would be small businesses.[10] For the 56 facilities affected by the shave and for which Dun and Bradstreet data is available, none are considered small businesses under either the SCAQMD or 1990 CAAA definitions. Twenty-two are considered small businesses under the SBA definition.[11]

7. COST OF BARCT INSTALLATION

This section estimates the total cost of BARCT installation. However, it should be noted that a RECLAIM facility is expected to retrofit an emission source only when it meets both of the following conditions: first, it does not hold sufficient RTCs to offset facility-wide emissions at the end of the compliance period; second, the cost of control installation per ton of emission reduction is lower than the expected average RTC price over the life of the control equipment. Even if a facility finds it more cost-effective to install pollution control equipment, it still would not incur the full cost of control installation if control installation results in surplus RTCs that the facility eventually sells to offset the control installation cost. Therefore, the compliance cost estimated in this section should be considered as the most conservative (i.e., maximum) estimate of the overall

[10] See the SBA website (http://www.sba.gov/community/blogs/community-blogs/small-business- matters/what-small-business-what-you-need-know-and-wh).The latest SBA definition of small businesses by industry can be found at http://www.sba.gov/content/table-small-business-size-standards.

[11] In order to reconcile discrepancies in Dunn & Bradstreet employment figures, estimates were acquired from SCAQMD Engineering & Compliance (RECLAIM Audit) permit data where applicable.

compliance cost for the proposed shave that will be needed to achieve the BARCT-equivalent level of NOx emission reductions.

Based on the BARCT analysis detailed in the Revised Draft Staff Report, the total compliance cost for BARCT installation would be potentially incurred by the 9 refineries and 11 non-refineries that have sources/equipment that can be upgraded to the 2015 BARCT level (for more detailed information on methodology and assumptions used, please see the Staff Report).Table 5 presents the estimated number of upgradable control devices at the 20 facilities per equipment/source category.

Under the proposed amendments, the 9 refineries would have the flexibility of changing operations, holding sufficient RTCs, or installing Selective Catalytic Reduction (SCR) technology, UltraCat Dry Gas Scrubbers (DGS), and Low Temperature Oxidation (LoTOxTM) with Wet Gas Scrubbers (WGS) to reduce NOx emissions coming from FCCUs, Sulfur Recovery Units/Tail Gas Incinerators (SRU/TGUs), coke calciner, refinery boilers and heaters, and refinery gas turbines.

The 11 non-refinery facilities currently have the following equipment/source categories: container glass melting furnaces, glass melting furnace facilities, sodium silicate furnaces, metal heat treating furnaces (rated greater than 150 mmBtu/hour), stationary ICEs and non- electricity generating facility stationary gas turbines. Under the proposed amendments, operators of these facilities would have the flexibility of changing operations, holding sufficient RTCs, or installing SCR technology or UltraCat DGS to reduce NOx emissions. For the purpose of conducting a worst-case analysis, 34 SCR units and 1 UltraCat DGS are assumed to be installed at the 11 non-refinery affected facilities. It is possible that another UltraCat DGS may also be installed in lieu of 1 of the 34 SCR units.

In total, the proposed project is assumed to result in the installation of the following new NOx air pollution control equipment: 116 SCRs, 8 LoTOxTM with WGSs, 1 LoTOxTM without WGS, and 3 UltraCat DGSs.

Table 5: Estimated Number of NOx Control Devices per Sector and Equipment/Source Category

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	5	3 SCRs 2 LoTOx™ with WGSs 1 LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	8	73 SCRs
Refinery	Refinery Gas Turbines	5	7 SCRs + Add Catalysts to 4 SCRs
Refinery	Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	4	5 LoTOx™ with WGSs and 1 SCR**
Refinery	Petroleum Coke Calciner	1	1 UltraCat DGS or LoTOx™ ***
Non-Refinery	Container Glass Melting Furnaces	1	2 SCR or 1 UltraCat DGS
Non-Refinery	Sodium Silicate Furnaces	1	1 SCR or 1 UltraCat DGS

Sector	Equipment/Source Category	Number of Affected Facilities	Estimated Number of Control Devices
Non-Refinery	Metal Heat Treating Furnaces	1	1 SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Electricity Generating)	3	16 SCRs
Non-Refinery	Turbines (Non-Refinery/ Non-Electricity Generating)	7	13 SCRs and 1 SCR replacement
		TOTAL	**116 SCRs** **8 LoTOx™ with WGSs** **1 LoTOx™ without WGS** **3 UltraCat DGSs**

Under the assumption that all BARCT control devices listed above would be installed, an assumed implementation schedule was developed based on the required construction time (Table 6) and cost-effectiveness of control equipment (Table 7), which would ensure the achievement of projected emission reductions in 2018 and 2022. To the extent possible, it was assumed that the most cost-effective NOx control equipment would be installed or modified first, taking into account unit turnaround schedule information available to staff at this time. Table 8 summarizes the assumed implementation schedule.

Table 6: Construction Time by Source Category and Control Equipment

Non-Refinery		
Source Category	**Control Equipment**	**Required Time**
Sodium Silicate Furnace	SCR	2 years
ICE Engines	SCR	2 years
Container Glass Furnace	SCR/UltraCat DGS	2 years
Gas Turbines	SCR	2 years
Metal Heat Treating Furnace >150mmBtu/hr	SCR	2 years
Refinery		
Source Category	**Control Equipment**	**Required Time**
Refinery FCCU	SCR/ LoTOx™	3 Years
Coke Calciner	LoTOx™ /UltraCat DGS	3 Years
Boilers/Heaters	SCR	3 Years
Gas Turbines	SCR	2-3 years
SRU/TGs	SCR/ LoTOx™	3 Years

The cost estimates in this analysis are based on the combined estimates provided by SCAQMD consultants and staff for each affected facility. In addition, when applicable, the assumptions applied in the previous CEQA documents were used which analyzed similar equipment in both the 2005 amendments to NOx RECLAIM and the 2010 amendments to SOx RECLAIM.[12] Further, if a particular technology was identified as having a cost that exceeds $50,000 per ton for a particular facility, staff did not include that equipment as having feasible BARCT controls or emission reduction potential in the analysis. This is consistent with past practice for proposed RECLAIM amendments.

Table 7: Distribution of Control Equipment by Equipment Category and by Cost-Effectiveness

Equipment Category	Average DCF $/ton	Average LCF $/ton
Refinery Gas Turbine	$2,046	$3,250
Metal Heat Treating Furnace >150mmBtu/hr	$3,400	$5,500
Sodium Silicate Furnace	$4,750	$7,600
Glass Melting Furnace	$5,950	$9,450
Non-Refinery ICE Engine	$6,000	$9,600
Refinery FCCU	$8,200	$14,300
Non-Refinery Gas Turbine	$20,300	$32,500
Coke Calciner	$23,500	$38,000
Refinery Boiler/Heater	$28,000	$45,000
SRU/TG	$34,000	$56,000
Average	**$13,615**	**$22,120**

* DCF stands for Discounted Cash Flow and LCF stands for Levelized Cash Flow.
** Each of the cost-effective values in this table corresponds to the midpoint of the cost-effectiveness ranges reported in the Revised Draft Staff Report.

[12] Staff has met with three refineries who provided varying levels of detail regarding their projected costs that would occur for these facilities to comply with the proposed amendments. There is not sufficient information for staff to verify the WSPA cost estimates. Some of the difference related to staff using an incremental cost-effectiveness calculation, which assumes that 2005 BARCT levels are in place, which may or may not be the case for individual facilities, but is needed for a programmatic evaluation. The individual facilities include total costs, and often include full costs for additional equipment such as substations that may support the new control equipment, as well as other operations at the facility.

Table 8: Distribution of Control Equipment Categories by Installation Schedules

	2016		2018		2019		2020		2021		2022			
Categories	**# of Equip**	**tpd emi red**	**# of Equip**	**tpd emi red**	**# of Equip**	**tpd emi red**	**# of Equip**	**tpd emi red**	**# of Equip**	**tpd emi red**	**# of Equip**	**tpd emi red**	**Total Equip**	**Total tpd emi reductions**
Refinery Sector														
Ref Gas Turbines	0	0.04	add cat	2.4	1 SCR	0.13	1 SCR	0.21	3 SCR	0.96	2 SCR	0.39	7 SCR	4.14
FCCUs					1 SCR	0.07	1 SCR	0.06	1 LoTOxTM	0.06	1 LoTOxTM	0.15	2 SCR 3 LoTOxTM	0.43
					1 LoTOxTM	0.09								
Coke Calciners					1 LoTOxTM UltraCat DGS	0.17							LoTOxTM UltraCat DGS	0.17
Boilers/Heaters							7 SCR	0.10	9 SCR	0.10	9 SCR	0.08	74 SCR	0.94
							14 SCR	0.17	14 SCR	0.14	2 SCR	0.01		
							13 SCR	0.24	6 SCR	0.13				
SRU/TGs							1 LoTOxTM	0.06	1 LoTOxTM	0.06	1 LoTOxTM	0.05	5 LoTOxTM 1 SCR	0.32
									2 LoTOxTM & 1 SCR	0.15				
Subtotal		**0.04**		**2.40**		0.46		0.84		1.60		0.68		6.00
Non-Refinery Sector														
Sodium Silicate Furnace			1 SCR or UltraCat DGS	0.09									1 SCR or UltraCat DGS	0.09
ICE					16 SCR	0.84							16 SCR	0.84
Container Glass Furnace					1 SCR or 2 UltraCat DGS	0.24							1 SCR or 2 UltraCat DGS	0.24
Gas Turbines							14 SCR	1.04					14 SCR	1.04
Metal H. Furnace >150mmBtu/hr					1 SCR	0.56								0.56
Subtotal				**0.09**		**1.64**		**1.04**						**2.77**
Total Emission Red.		**0.04**		**2.49**		**2.10**		**1.88**		**1.60**		**0.68**		**8.77**
Proposed RTC Red.		**4**		**2**		**2**		**2**		**2**		**2**		**14**

Table 9 presents the total average annual compliance cost of the proposed amendments by source/equipment category. The detailed cost assumptions will be discussed in the following subsections. Only estimates using a 4 percent discount rate will be reported in those subsections.[13]

Table 9: Average Annualized Control Installation Cost Estimates by Equipment Category (Millions of 2014 dollars)

	2018		**2019**		**2022**		**2035**		**Average Annual (2018-2035)**	
	Discount Rate Applied									
	4%	**1%**	**4%**	**1%**	**4%**	**1%**	**4%**	**1%**	**4%**	**1%**
Source Category Refinery										
Refinery FCCU	0	0	9.4	7.82	25.25	21.03	25.25	21.03	21.86	18.18
Coke Calciner	0	0	5.83	4.89	5.83	4.89	5.83	4.89	5.51	4.62
Boilers/Heaters	0	0	0	0	15.17	11.06	15.17	11.06	13.03	9.5
Gas Turbines	1.23	1.17	1.69	1.61	6.12	5.87	6.12	5.87	5.35	5.13
SRU/TGs	0	0	0	0	6.77	4.97	6.77	4.97	5.64	4.14
Total Refinery	**1.23**	**1.17**	**16.92**	**14.32**	**59.14**	**47.81**	**59.14**	**47.81**	**51.39**	**41.57**
Source Category Non-Refinery										
Sodium Silicate Furnace	0.3	0.26	0.3	0.26	0.3	0.26	0.3	0.26	0.3	0.26
ICE Engines	0	0	2.38	1.98	2.38	1.98	2.38	1.98	2.25	1.87
Container Glass Furnace	0	0	0.93	0.82	0.93	0.82	0.93	0.82	0.88	0.78
Gas Turbines	0	0	0	0	6.96	6.38	6.96	6.38	6.19	5.67
Total Non-Refinery	**0.30**	**0.26**	**4.23**	**3.63**	**11.19**	**10.00**	**11.19**	**10.00**	**10.20**	**9.11**
Grand Total	**1.53**	**1.43**	**21.15**	**17.95**	**70.32**	**57.81**	**70.32**	**57.81**	**61.59**	**50.68**

[13] In 1987, SCAQMD staff began to calculate cost-effectiveness of control measures and rules using the Discounted Cash Flow method with a discount rate of 4 percent. Although not formally documented, the discount rate is based on the 1987 real interest rate on 10-year Treasury Notes and Bonds, which was 3.8 percent. The maturity of 10 years was chosen because a typical control equipment life is 10 years; however, a longer equipment life would not have corresponded to a much higher rate-- the 1987 real interest rate on 30-year Treasury Notes and Bonds was 4.4 percent. Since 1987, the 4 percent discount rate has been used by SCAQMD staff for all cost-effectiveness calculations, including BACT analysis, for the purpose of consistency. The compliance cost reported in this assessment was thus annualized using a real interest rate of 4 percent. As a sensitivity test, a real interest rate of 1 percent was also used, which is closer to the prevailing real interest rate (see https://www.whitehouse.gov/omb/circulars_a094/a94_appx-c/).

As shown in Table 9, more expensive controls would not be installed until the 2019- 2022 timeframe. Based on this schedule and facility-specific estimates, the average annualized cost of the proposed amendments is estimated to be approximately $70 million (at 4 percent discount rate) or $60 million (at 1 percent discount rate) from year 2022 onwards when all controls are assumed to have been installed. More than 73 percent of the annualized compliance cost is expected to occur in the refinery sector, and more than 43 percent of the sector's annualized compliance cost would be associated with FCCU installation. Among the non-refinery sectors, gas turbines would account for more than 60 percent of the sector's annualized compliance cost.

Table 10 presents the annual compliance cost of full BARCT implementation by industry. Refineries (NAICS 324) would incur the majority of the compliance costs. Among the non- refinery sectors, glass melting furnaces, sodium silicate furnaces and metal heat treating furnaces belong to nonmetallic mineral product manufacturing (NAICS 327), chemical manufacturing (NAICS 325), and primary metal manufacturing (NAICS 311) sectors. Gas turbines were used in airport operations (NAICS 488), oil and gas extraction (NAICS 211), and paper manufacturing (NAICS 322) sectors. Internal Combustion Engines (ICE) engines were used in the utilities sector (NAICS 221).

Table 10: Average Annualized Control Installation Cost Estimates by Industry (Millions of 2014 dollars)

	2018		2019		2022		2035		Average Annual (2018-2035)	
	Discount Rate Applied									
	4%	1%	4%	1%	4%	1%	4%	1%	4%	1%
Refineries (324)	1.23	1.17	16.92	14.32	59.14	47.81	59.14	47.81	51.39	41.57
Utility (221)	0.00	0.00	2.38	1.98	6.27	5.57	6.27	5.57	5.72	5.06
Air Port Operation (488)	0.00	0.00	0.36	0.30	0.36	0.30	0.36	0.30	0.32	0.27
Paper Manufacturing (322)	0.00	0.00	0.00	0.00	0.73	0.68	0.73	0.68	0.65	0.60
Oil and Gas Extraction (211)	0.00	0.00	0.00	0.00	1.97	1.80	1.97	1.80	1.75	1.60
Nonmetallic Mineral Product Mfg. (327)	0.00	0.00	0.93	0.82	0.93	0.82	0.93	0.82	0.88	0.78
Chemical Manufacturing (325)	0.30	0.26	0.30	0.26	0.30	0.26	0.30	0.26	0.30	0.26
Primary Metal Manufacturing (311)	0.00	0.00	0.62	0.57	0.62	0.57	0.62	0.57	0.59	0.54
Grand Total	**1.53**	**1.43**	**21.15**	**17.95**	**70.32**	**57.81**	**70.32**	**57.81**	**61.59**	**50.68**

7.1 BARCT Cost Estimates for the Refinery Sector

There are 9 refinery facilities subject to the NOx RECLAIM rules whose operators may choose to install NOx air pollution control equipment in response to the proposed RTC shave. These facilities include the 6 refineries owned by 5 companies operating FCCUs, refinery boilers and heaters, refinery gas turbines, and SRU/TGUs.

As discussed previously, the 9 refineries may choose among changing operations, obtaining sufficient RTC holdings, and installing NOx control devices, presumably based on which option would be more economical. The analysis herein assumes that the 9 refineries would install BARCT controls under the proposed amendments, a scenario representing the maximum potential cost.

As a conservative approach to cost estimation, the most stringent controls with the high- end cost (worst case scenarios) are assumed for the proposed amendments as well as for the CEQA alternatives. In total, 84 SCR units, 6 LoTOxTM with WGSs, 1 LoTOxTM without WGS, and 1 UltraCat DGS are assumed to be installed at the 9 refinery sector facilities. In order to operate SCR and UltraCat DGS, ammonia is necessary and, as such, tanks to store ammonia would also need to be installed. The size of each ammonia tank needed to operate the SCR units and 1 UltraCat DGS have been estimated to range between 2,000 and 11,000 gallons in capacity. For a full description of the control technologies, please see the CEQA NOx Control Technologies section.

7.1.1 Refinery FCCUs

The purpose of an FCCU at a refinery is to convert or "crack" heavy oils (hydrocarbons), with the assistance of a catalyst, into gasoline and lighter petroleum products. Each FCCU consists of three main components: a reaction chamber, a catalyst regenerator and a fractionator. There are 5 refineries that operate 6 FCCUs in the SCAQMD. The FCCUs are classified as major sources of emissions in RECLAIM, and as such, the NOx emissions from FCCUs are required to be monitored with a continuous emission monitoring system (CEMS), and reported on a daily basis electronically to the SCAQMD.

To further reduce NOx emissions from a FCCU (beyond what is currently being achieved through the use of NOx reducing additives), the potential available control technologies are either: 1) SCR; or, 2) LoTOxTM with WGS.

Two out of the 5 affected refineries are assumed to install SCRs and the remaining 3 are assumed to install LoTOxTM with WGS. The total compliance cost of the proposed amendments for refinery FCCUs includes one-time cost and recurring cost. The one-time cost includes the capital cost of SCRs and LoTOxTM with WGS and their installations (demolition, concrete, structural, piping, electrical, contractors, contingencies).

The capital cost and installation of the 2 SCRs are estimated at $30 and $48.3 million, respectively. Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the capital cost and installation of the 3 LoTOxTM with WGSs are estimated at $33.47, $54.89, and $60.62 million, respectively. Assuming a 25-year life[14] for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of compliance for the refinery FCCUs would sum up to $14.53 million.

The annual operating costs for the 2 SCR units include utilities (electricity), ammonia, catalyst

[14] Although the Bay Area AQMD and EPA OAQPS assume an SCR lifespan of 20 years, staff assumed a 25-year equipment life for SCRs to be installed based on the profiles of SCRs used by refineries in the Basin. Nearly 30 percent of the refinery combustion equipment in the Basin has SCRs that were installed more than 25 years ago, and more than 60 percent of the refinery combustion equipment has SCRs that were installed more than 20 years ago. These units are still in operation and thus support the assumption of a 25-year useful life in the cost analysis.

replacement (every 5 years), and other periodic maintenance. The annual operating cost for each SCR unit is estimated at $0.12 and $0.19 million, respectively. The catalyst replacement costs for each SCR unit is estimated at $1.5 million and $2.4 million, respectively. Staff used data provided in the 2005 SOx RECLAIM amendments for the annual costs associated with the WGS and manufacturer's data for the annual costs associated with the LoTOxTM with WGS portion of the system. The annual operating costs for the 3 LoTOxTM with WGSs units include utilities (electricity), ammonia/caustic, waste water, and other periodic maintenance. The annual operating cost for each LoTOxTM with WGS unit is estimated at $2.4 and $3.5, and $3.9 million, respectively. The total annualized operating and maintenance costs for the 2 SCRs and 3LoTOxTM with WGS units would sum up to about $10.7 million.[15] Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the FCCU units would amount to $25 million using a 4 percent discount rate.

Table 11: Total Capital, Installation, and Annual Operating Cost of SCRs/LoTOx™ for Refineries FCCUs (Millions of 2014 dollars, present value)

Refinery	Equipment Cost	Installation Cost	Total O&M Cost	Electricity/ Water	Ammonia/ Caustic	Catalyst*
5	$7.5	$22.5	$0.12	$0.036	$0.084	$1.5
6	$12.0	$36.0	$0.192	$0.058	$0.134	$2.4
7	$9.6	$23.9	$2.14	$0.64	$1.49	0.0
4	$15.6	$39.0	$3.51	$1.05	$2.45	0.0
9	$17.3	$43.3	$3.88	$1.16	$2.7	0.0
Total	**$62.00**	**$164.70**	**$9.84**	**$2.94**	**$6.86**	**$3.90**

*Total cost recurring every 5 years

7.1.2 Refinery Process Heaters and Boilers

Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. There are 23 boilers and 189 heaters in the refineries classified as major or large NOx sources. The refinery heaters and boilers primarily burn refinery gas which is generated at the refinery. Most of these boilers and heaters use natural gas as back-up or supplemental fuel.

For the purpose of the analysis, controlling NOx emissions from refinery boilers and process heaters was assumed to be accomplished with SCR technology. It was assumed that 8 refineries would

[15] The total O&M cost in Table 11 is the sum of annual electricity/water, ammonia/caustic and annualized cost of the catalyst.

install 73 SCR units. Based on the vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital, installation, and operating costs of each SCR is presented in the table below. It should be noted that the annual operating costs were distributed among electricity, ammonia, annual catalyst replacement, and other annual maintenance.

Assuming a 25-year life for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of compliance of 73 SCR installations for the refinery boilers and heaters is estimated at $15.02 million. The total annual operating and maintenance costs for the 73 SCR units are estimated at $0.15 million.[16] Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the boilers and heaters would amount to $15 million using a 4 percent discount rate. Table 12 presents the detailed costs per refinery.

Table 12: Total Capital, Installation, and Annual Operating Cost of SCRs for Refineries Process Heaters and Boilers (Millions of 2014 dollars, present value)

Refinery	Equipment Cost	Installation Cost	Total O&M in $1,000	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
1	$7.36	$25.80	$21.44	$6.43	$8.58	$4.29	$2.14
3	$0.44	$1.54	$1.28	$0.38	$0.51	$0.26	$0.13
4	$4.51	$15.79	$13.12	$3.94	$5.25	$2.62	$1.31
5	$10.87	$38.12	$31.69	$9.51	$12.67	$6.34	$3.17
6	$11.32	$39.67	$32.97	$9.89	$13.19	$6.59	$3.30
7	$7.80	$27.34	$22.72	$6.82	$9.09	$4.54	$2.27
8	$3.85	$13.48	$11.20	$3.36	$4.48	$2.24	$1.12
9	$5.93	$20.80	$17.28	$5.18	$6.91	$3.46	$1.73
Total	**$52.08**	**$182.54**	**$151**	**$45.51**	**$60.68**	**$30.34**	**$15.17**

7.1.3 Refinery Gas Turbines

Gas turbines are used in refineries to produce both electricity and steam. Refinery gas turbines are typically combined cycle units that use 2 work cycles from the same shift operation. There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tpd of NOx in 2011.

For the purpose of the analysis, controlling NOx emissions from refinery gas turbines was assumed to be accomplished with SCR technology. A total of 5 refineries are affected in this category. Refinery 1 is assumed to add catalyst to existing SCRs and the remaining 4 refineries are assumed to install SCRs: Refinery 4 (2 SCRs), Refinery 3 (3 SCRs), Refinery 6 and 7 each to install 1 SCR.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital, installation, and operating costs of each SCR is presented in the table below. It should be

[16] The total O&M cost in Table 12 is the sum of annual electricity/water, ammonia/caustic, annual cost of the catalyst, and other maintenances.

noted that the annual operating costs were distributed among electricity, ammonia, annual catalyst replacement, and other annual maintenance. Assuming a 25-year life for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of compliance of the SCRs installations for the refinery gas turbines is estimated at $1 million. The total annual operating and maintenance costs of SCR units are estimated at $5.25 million.[17] Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the gas turbines would amount to $6 million using a 4 percent discount rate. Table 13 presents the detailed costs per refinery.

Table 13: Total Capital, Installation, and Annual Operating Cost of SCRs for Refineries Gas Turbines (Millions of 2014 dollars, present value)

Refinery	Equipment Cost	Installation Cost	Total O&M Cost	Electricity/ Water	Ammonia /Caustic	Catalyst	Other Maintenances
1	$0.77	$2.30	$1.03	$0.31	$0.41	$0.21	$0.10
4	$0.71	$2.14	$0.96	$0.29	$0.38	$0.19	$0.09
5	$1.51	$4.54	$2.03	$0.61	$0.81	$0.41	$0.20
6	$0.29	$0.86	$0.39	$0.12	$0.15	$0.08	$0.04
7	$0.63	$1.89	$0.85	$0.25	$0.34	$0.17	$0.09
Total	**$3.91**	**$11.73**	**$5.25**	**$1.58**	**$2.09**	**$1.06**	**$0.52**

7.1.4 Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal. The type of NOx control option to be utilized in response to this portion of the proposed project is assumed to be LoTOxTM technology with a WGS or SCR. Three refineries are assumed to install 1 LoToxTM with WGS each and 1refinery is assumed to install 2 LoTOxTM with WGS and 1 SCR.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital, installation, and operating costs of LoTOxTM with WGS and SCR are presented in the table below. It should be noted that the annual operating costs were distributed among electricity, ammonia/caustic, waste water, annual catalyst replacement, and other annual maintenance.

Assuming a 25-year life for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of compliance of the LoTOxTM with WGS and SCR installations for the refinery SRU/TGUs is estimated at $6.2 million. The total annual operating and maintenance costs

[17] The total O&M cost in Table 13 is the sum of annual electricity/water, ammonia/caustic, annual cost of the catalyst, and other maintenances.

are estimated at $0.57 million.[18] Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the gas turbines would amount to $7 million using a 4 percent discount rate. Table 14 presents the detailed costs per refinery.

Table 14: Total Capital, Installation, and Annual Operating Cost of Sulfur Recovery Units and Tail Gas Units (SRU/TGUs) (Millions of 2014 dollars, present value)

Refinery	Equipment Cost	Installation Cost	Total O&M Cost	Electricity/ Water	Ammonia/ Caustic	Waste Water	Other Maintenance
1	$4.52	$15.82	$0.15	$0.07	$0.06	$0.01	$0.01
5	$7.91	$27.68	$0.14	$0.07	$0.05	$0.01*	$0.01
6	$4.57	$15.99	$0.13	$0.07	$0.05	$0.01	$0.01
8	$4.52	$15.82	$0.15	$0.07	$0.06	$0.01	$0.01
Total	**$21.52**	**$75.31**	**$0.57**	**$0.28**	**$0.21**	**$0.04**	**$0.04**

***** Refinery 5 cost estimates for annual cost of catalyst

7.1.5 Petroleum Coke Calciner

Petroleum coke is the heaviest portion of crude oil which cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as "green coke," a commodity. To improve the quality of the product, it is sent to a calciner to make calcined petroleum coke.

There are two commercially available multi-pollutant control technologies for the low temperature removal of NOx emissions from the coke calciner: 1) LoTOxTM with scrubber; and, 2) UltraCat DGS. The type of NOx control option to be utilized for the coke calciner in response to the proposed amendments would depend on the facility's individual operations and the current control technologies and techniques in place. For the purpose of the socioeconomic analysis, 1 refinery is assumed to control NOx emissions from a coke calciner with UltraCat DGS. It should be noted that the annual operating costs were distributed among electricity, ammonia, waste water, annual catalyst replacement, and other annual maintenance.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital and installation of LoTOxTM with UltraCat DGS is estimated at $50.84 million. Assuming a 25-year life for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of compliance of 1 UltraCat DGS is estimated at $3.25 million. The total annual operating and maintenance costs are estimated at $2.58 million. Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the coke calciner would amount to

[18] The total O&M cost in Table 14 is the sum of annual electricity/water, ammonia/caustic, waste water, and other maintenances.

$6 million using a 4 percent discount rate.

7.2 BARCT Cost Estimates for the Non-Refinery Sector

In addition to the 9 refineries, 11 non-refinery facilities also operate with equipment that can be further controlled to meet 2015 BARCT levels. They include 1 container glass manufacturing plant, 1 sodium silicate manufacturing plant, 1 steel plant operating 2 metal heat treating furnaces rated greater than 150 mmBtu/hr, 7 facilities operating gas turbines, and 3 facilities operating ICEs. The analysis herein assumes that the 11 non-refinery facilities would choose to install BARCT controls under the proposed amendments, the maximum potential compliance cost scenario.

As a conservative approach to cost estimation, the most stringent controls with the high- end cost (worst case scenarios) are assumed for the proposed amendments as well as for the CEQA alternatives. In total, 34 SCR units and 1 UltraCat DGS are assumed to be installed at these facilities.

7.2.1 Container Glass Melting Furnaces

A container glass melting furnace is the main equipment used for manufacturing glass products, such as bottles, glassware, pressed and blown glass, tempered glass, and safety glass. In the NOx RECLAIM program there is 1 facility among the top NOx emitting facilities that operates glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

To effectively reduce NOx emissions from this category, staff assumed the affected facility would chose to install 2 Tri-Mer UltraCat Systems for treating the flue gas of glass melting furnaces. Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital and installation of 2 Tri-Mer UltraCat Systems is estimated at
$5.68 million. Assuming a 25-year life for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of compliance of 2 UltraCat DGS is estimated at $0.36 million. The total annual operating and maintenance costs are estimated at $0.67 million. The annual operating costs were distributed among electricity, ammonia and sorbent, waste water, waste disposal, annual catalyst replacement, and other annul maintenance. The total annualized cost of compliance for the container glass melting furnace including capital, operating, and maintenance, is estimated to be $1.03 million.

7.2.2 Sodium Silicate Furnace

In the NOx RECLAIM program, there is only 1 facility that produces sodium silicate in a melting furnace. NOx emissions are also created from combusting fuel needed to heat the furnace. To effectively achieve the largest reduction of NOx emissions, it was assumed that the affected facility would choose to install 1 UltraCat DGS.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital and installation costs of 1 UltraCat DGS is estimated at $2 million. Assuming a 25-year life for equipment and installation, and a real interest rate of 4 percent, the total one-time annualized cost of 1 UltraCat DGS is estimated at $0.13 million. The total annual operating and maintenance costs are estimated at $0.17 million. The annual operating costs were distributed among electricity, ammonia, waste water, waste disposal, annual catalyst replacement, and other annual maintenance. Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the container glass melting furnace would amount to $300,000 using a 4 percent discount rate.

7.2.3 Metal Heat Treating Furnaces

A metal melting furnace burns liquid or gaseous fuel to generate enough pre-heated air at a temperature high enough to melt solid metal into a liquid molten consistency and to maintain the metal in a liquid state until it is ready for later use. Among the top NOx emitting facilities in the NOx RECLAIM program, there is only 1 facility that processes steel in 2 metal heat furnaces with individual heat ratings above 150 mmBtu/hr. To effectively achieve a substantial NOx reduction from these metal heat treating furnaces, SCR is the technology that is best suited for the flue gas treatment of NOx. As a result, it was assumed that the operator of the affected facility would chose to install 1 SCR system.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital and installation of 1 SCR is estimated at $2.80 million. Assuming a 25- year life for equipment and installation, and a real interest rate of 4 percent, the total one- time annualized compliance cost is estimated at $0.18 million. The total annual operating and maintenance costs are estimated at $0.44 million. The annual operating costs were distributed among electricity, ammonia, annual catalyst replacement, and other annual maintenance. Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the metal melting furnace would amount to $600,000 using a 4 percent discount rate.

7.2.4 Gas Turbines (Non-Refinery/Non-Electricity Generating Plant)

Stationary gas turbines are used primarily to drive compressors or to generate electricity. Among the top non-electricity generating facility NOx emitting facilities in the RECLAIM universe, there are 20 gas turbines that are either major or large source units. For the purpose of the analysis, controlling NOx emissions from the 4 non-refinery/non-electricity generating facility gas turbines is assumed to be accomplished with SCR technology.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital, installation, and operating costs of 14 SCRs for the 7 affected facilities are presented in the table below. It should be noted that the annual operating costs were distributed among electricity, ammonia and annual catalyst replacement. Assuming a 25- year life for equipment and installation, and a real interest rate of 4 percent, the total one- time annualized cost of compliance of 14 SCRs is estimated at $2.02 million. The total annual operating cost of these 14 SCRs is estimated at $4.94 million.[19] Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the gas turbines would amount to $7 million using a 4 percent discount rate. Table 15 presents the detailed costs per facility.

[19] The total O&M cost in Table 15 is the sum of annual electricity, ammonia/urea, and annual cost of catalyst.

Table 15: Total Capital, Installation, and Annual Operating Cost of SCRs for Non-Electricity generating facilities Gas Turbines (Millions of 2014 dollars, present value)

Facility	Equipment Cost	Installation Cost	Total O&M Cost	Electricity	Ammonia /Urea	Catalyst
1	$2.81	$5.62	$2.12	$0.41	$1.34	$0.37
2	$2.03	$4.06	$0.27	$0.08	$0.15	$0.03
3	$0.77	$1.55	$0.44	$0.02	$0.32	$0.10
4	$0.96	$1.92	$0.17	$0.04	$0.09	$0.04
5	$0.92	$1.84	$0.56	$0.02	$0.35	$0.19
6	$1.62	$3.25	$0.79	$0.27	$0.29	$0.23
7	$1.40	$2.81	$0.6	$0.2	$0.2	$0.2
Total	**$10.51**	**$21.05**	**$4.95**	**$1.04**	**$2.74**	**$1.16**

7.2.5 Internal Combustion Engines (Non-Refinery/Non-Electricity Generating Facility)

Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate electricity. For the purpose of the analysis, controlling NOx emissions from this category is assumed to be accomplished with SCR technology.

Based on vendor–supplied costs and the assumptions made in staff's engineering analyses, the total capital, installation, and operating costs of 16 SCRs for the 3 affected facilities are presented in the table below. It should be noted that the annual operating costs were distributed among electricity, ammonia and annual catalyst replacement. Assuming a 25- year life for equipment and installation, and a real interest rate of 4 percent, the total one- time annualized cost of compliance of 16 SCRs is estimated at $1.38 million. The total annual and operating costs of these 16 SCRs is estimated at $0.99 million.[20] Summing up the capital, operating, and maintenance costs, total annualized cost of compliance for the ICEs would amount to $2 million using a 4-percent discount rate. Table 16 presents the detailed costs per facility.

[20] The total O&M cost in Table 16 is the sum of annual electricity, ammonia/urea, annual cost of catalyst, and other maintenances.

Table 16: Total Capital, Installation, and Annual Operating Cost of SCRs for Non- Electricity generating facilities ICE Engines (Millions of 2014 dollars, present value)

Facility	Equipment Cost	Installation Cost	Total O&M Cost	Electricity	Ammonia /Urea	Catalyst	Other Maintenances
1	$0.53	$3.93	$0.18	$0.005	$0.08	$0.08	$0.02
2	$0.68	$4.78	$0.31	$0.004	$0.07	$0.22	$0.02
3	$0.80	$10.80	$0.50	$0.01	$0.21	$0.22	$0.06
Total	**$2.01**	**$19.51**	**$0.99**	**$0.02**	**$0.36**	**$0.52**	**$0.10**

8. MACROECONOMIC IMPACTS ON REGIONAL ECONOMY

The Regional Economic Model (REMI, PI+ v1.7.2) (PI+ v1.7.2) was used to assess the total socioeconomic impacts of a policy change (i.e., the proposed rule). The model links the economic activities in the counties of Los Angeles, Orange, Riverside, and San Bernardino, and for each county, it is comprised of five interrelated blocks: (1) output and demand, (2) labor and capital, (3) population and labor force, (4) wages, prices and costs, and (5) market shares.[21]

8.1 Impact of Proposed Amendments

The assessment herein is performed relative to a baseline ("business as usual") where the proposed amendments would not be implemented. The proposed amendments are assumed to induce full BARCT installation at the 9 refineries and 11 non-refinery facilities, which would create a policy scenario under which the affected facilities would incur a total annual compliance cost of approximately $70 million when evaluated at a 4 percent discount rate, or $60 million when evaluated at a 1 percent discount rate from year 2022 onwards when all controls are assumed to have been installed. It is assumed that the 20 facilities would finance the capital and installation costs of control equipment, or more specifically, these one-time costs are assumed to be amortized and incurred over the equipment life.

Direct effects of the proposed amendments are used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all the industries in the four- county economy on an annual basis and across a user-defined horizon: 2018 (first year of assumed BARCT implementation) to 2035, and a sensitivity analysis was conducted that extends the horizon to

[21] Within each county, producers are made up of 66 private non-farm industries, three government sectors, and a farm sector. Trade flows are captured between sectors as well as across the four counties and the rest of U.S. Market shares of industries are dependent upon their product prices, access to production inputs, and local infrastructure. The demographic/migration component has 160 age/gender/race/ethnicity cohorts and captures population changes in births, deaths, and migration. (For details, please refer to REMI online documentation at http://www.remi.com/products/pi.)

2043. Direct effects of the proposed amendments include additional costs to the 20 facilities that would install control equipment and additional sales, by local vendors, of equipment, devices, or services that would meet the proposed requirements. Whereas all the compliance expenditures that are incurred by the affected facilities would increase their cost of doing business, the purchase of additional control equipment such as SCR, LoTOxTM, UltraCat DGS, and equipment installation would increase the spending and sales of businesses in various sectors, some of which may be located in the SCAQMD region. Table 17 lists the industry sectors modeled in REMI that would either incur cost or benefit from the compliance expenditures.

Table 17: Industries Incurring *vs.* Benefitting from Compliance Costs/Spending

Source of Compliance Costs	REMI Industries Incurring Compliance Costs (NAICS)	REMI Industries Benefitting from Compliance Spending (NAICS)
Installation of SCR, LoTOx™, UltraCat DGS	Refinery (NAICS 324), Manufacturing (NAICS 331), Utilities (NAICS 221), Chemical Manufacturing (NAICS 325), Nonmetallic Mineral Product Manufacturing (NAICS 327), Oil and Gas Extraction (NAICS 211), and Support Activities for Transportation (NAICS 488)	*One-time-Capital:* Machinery Manufacturing (NAICS 333)
Installation of SCR, LoTOx™, UltraCat DGS	Refinery (NAICS 324), Manufacturing (NAICS 331), Utilities (NAICS 221), Chemical Manufacturing (NAICS 325), Nonmetallic Mineral Product Manufacturing (NAICS 327), Oil and Gas Extraction (NAICS 211), and Support Activities for Transportation (NAICS 488)	*One-time-Capital:* Construction (236)
Operating and Maintenance Cost of SCR, LoTOx™, UltraCat DGS	Refinery (NAICS 324), Manufacturing (NAICS 331), Utilities (NAICS 221), Chemical Manufacturing (NAICS 325), Nonmetallic Mineral Product Manufacturing (NAICS 327), Oil and Gas Extraction (NAICS 211), and Support Activities for Transportation (NAICS 488)	*Recurring:* Professional, Scientific, and Technical Services (541)
Other Operating and Maintenance Costs: Electricity, Water	Refinery (NAICS 324), Manufacturing (NAICS 331), Utilities (NAICS 221), Chemical Manufacturing (NAICS 325), Nonmetallic Mineral Product Manufacturing (NAICS 327), Oil and	*Recurring:* Utilities (221)

Source of Compliance Costs	REMI Industries Incurring Compliance Costs (NAICS)	REMI Industries Benefitting from Compliance Spending (NAICS)
	Gas Extraction (NAICS 211), and Support Activities for Transportation (NAICS 488)	
Other Operating and Maintenance Costs: Ammonia, Caustic, Oxygen	Refinery (NAICS 324), Manufacturing (NAICS 331), Utilities (NAICS 221), Chemical Manufacturing (NAICS 325), Nonmetallic Mineral Product Manufacturing (NAICS 327), Oil and Gas Extraction (NAICS 211), and Support Activities for Transportation (NAICS 488)	*Recurring:* Chemical Manufacturing (NAICS 325)
Other Operating and Maintenance Costs: Solid Waste Disposal & Waste Water	Refinery (NAICS 324)	*Recurring:* Waste Management (NAICS 562)

It should be noted that the REMI model is not designed to assess impacts on individual operations. The model was used to assess the impacts of the proposed amendments on various industries that make up the local economy. Cost impacts on individual operations were assessed outside of the REMI model and used as inputs into the REMI model.

When the compliance cost annualized at a 4 percent interest rate is used, it is projected that an average of 20 net jobs could be created annually from 2018 to 2035, and about 140 net jobs foregone when the analysis horizon is extended to 2043. The difference is because the majority of jobs would be created at the beginning of the analysis period (2018-2022) when control installation is assumed to take place, as shown in Figure 2. (Note that jobs foregone may include either losses of existing jobs or projected additional jobs not created). The projected job impact becomes slightly more positive when the compliance cost annualized at a 1 percent interest rate is used. This analysis only considers the potential compliance cost of full BARCT installation at the 20 facilities, and it does not take into account the monetary benefits for facilities that potentially will have more RTCs available for sale as a result of NOx emission reductions due to BARCT installation. (Please see next section for an RTC market analysis.)

In earlier years of the implementation of these amendments, the positive job impacts from the compliance expenditures made by refineries, container glass, sodium silicate plant, and sulfur acid plants would more than offset the jobs forgone from the additional cost of doing business (Table 18). In 2021, where most of the spending is expected to occur, about 2,000 additional jobs are projected in the regional economy. The positive job impact would trickle down to the sectors of construction, miscellaneous professional services, retail, wholesale, and business services. However, as refineries, glass, sulfur acid plant, and other non-major facilities continue to incur the amortized capital expenditures, reductions in job growth would set in, resulting in jobs forgone in later years.

The oil and gas extraction sector is projected to have about 30 average annual jobs forgone, due to additional spending on SCRs required on gas turbines. Despite having a large share of the total compliance cost, the refinery industry is projected to have fewer jobs forgone (about 10) relative to other industries with a similar magnitude of cost impacts. This is due to the fact that the industry is the most capital-intensive. As such, less labor would be required to produce the same amount of products or services.

In earlier years, positive job impacts are projected in the sectors of fabricated metal products (NAICS 332) and machinery manufacturing (NAICS 331), due to purchase of various types of control equipment (including SCR, LoTOxTM, and UltraCat DGS) by the affected facilities (as presented in Table 17). Likewise, the sector of construction is projected to gain many jobs during the beginning period, due to the installation of control equipment. In addition, the sector of professional and technical services (NAICS 541) is projected to also gain jobs in earlier years from additional demand for equipment installation and maintenance. Operating and maintenance expenditures would benefit the industries of chemical products (NAICS 325) for additional sales of ammonia and public utilities (NAICS 22) for electricity.

The projected reduction in disposable income from the overall jobs forgone in the later years would dampen the demand for goods and services in the local economy, thus contributing to jobs forgone in sectors such as the rest of manufacturing, retail trade, wholesale, and accommodation and food services. As presented in Table 18, many major sectors of the regional economy would experience negative, albeit minor, job impacts in later years from the secondary and induced effects of BARCT implementation.

Table 18: Projected Job Impacts of Full BARCT Implementation by Industry and Year

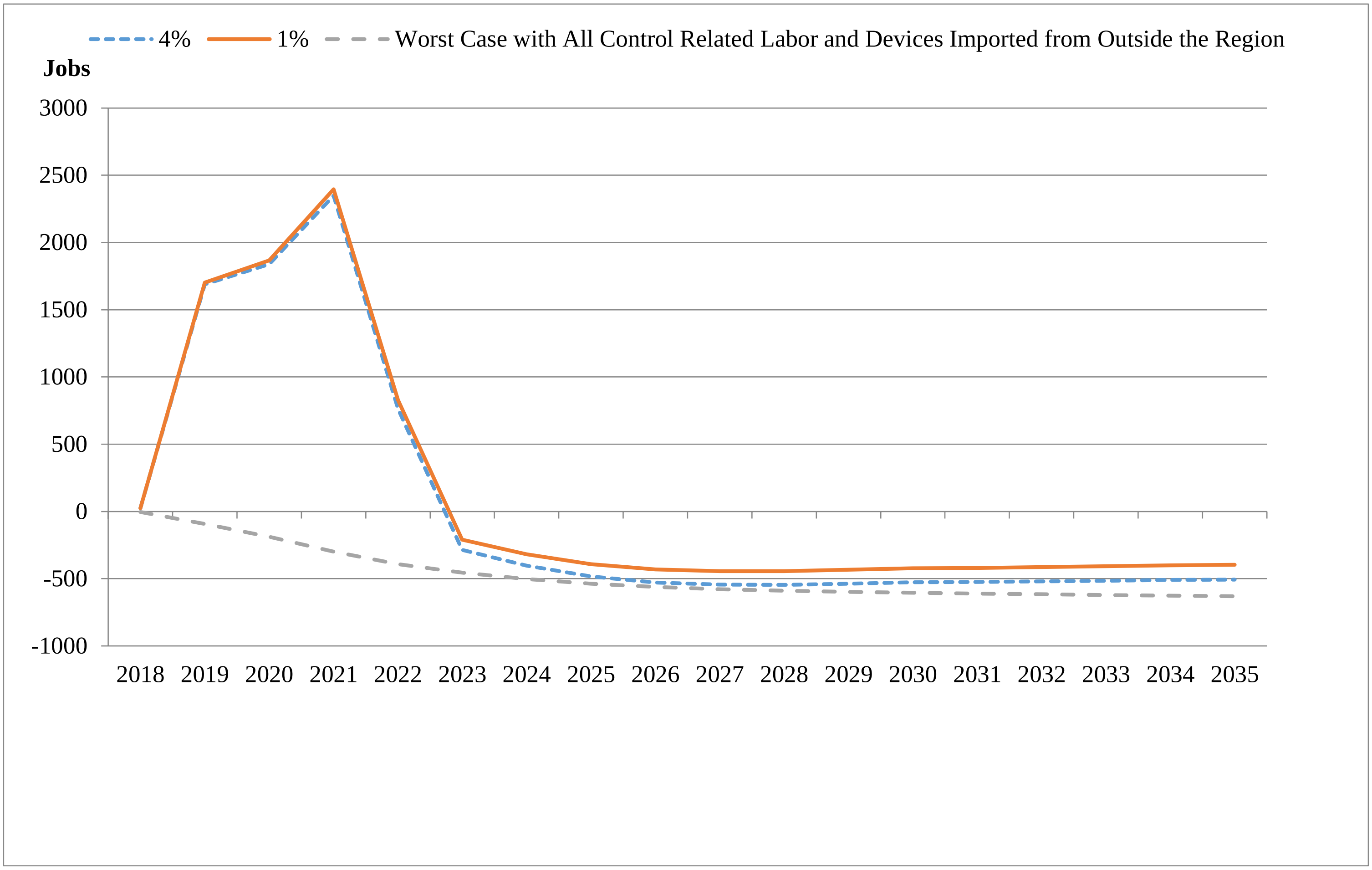
Industry	NAICS	Year					Average Annual (2018-2035)
		2018	2021	2022	2030	2035	
Oil and gas extraction	211	0	-10	-19	-43	-45	-31
Utilities	22	0	5	5	1	1	2
Construction	23	23	1193	476	-114	-84	116
Nonmetallic mineral product mfg.	327	0	9	3	-2	-2	0
Fabricated metal product mfg.	332	1	21	8	-4	-3	1
Machinery mfg.	331	2	44	22	2	1	9
Petroleum and coal product mfg.	324	0	-4	-7	-13	-12	-9
Chemical mfg.	325	0	5	4	2	1	2
Rest of Manufacturing	31-33	0	24	1	-13	-11	-7
Wholesale trade	42	1	56	22	-5	-6	6
Retail trade	44-45	2	95	6	-59	-57	-27
Truck transportation and couriers	484,492	0	13	3	-5	-4	-1
Monetary authorities	521,522,5255	0	14	5	-2	-2	1
Securities, and commodity contracts	523	1	31	5	-6	-4	0
Insurance carriers and related activities	524	0	10	3	-3	-3	0
Real estate	531	1	43	13	-19	-19	-6
Professional and technical services	54	4	125	54	-30	-39	2

Industry	NAICS	Year					Average Annual (2018-2035)
		2018	2021	2022	2030	2035	
Management of companies and enterprises	55	0	9	2	-3	-2	-1
Administrative and support services	561	2	87	28	-26	-26	-4
Waste management and remediation services	562	0	3	2	-1	-2	0
Educational services	61	1	24	8	-8	-8	-1
Ambulatory health care services	621	1	64	18	-17	-19	-2
Hospitals	622	0	14	5	-6	-7	-2
Nursing and residential care facilities	623	0	11	3	-4	-5	-1
Social assistance	624	1	36	11	-11	-13	-2
Performing arts and spectator sports	711	0	9	0	-1	0	0
Amusement, gambling, and recreation	713	0	6	2	-1	-1	0
Accommodation	721	0	11	3	-3	-3	0
Food services and drinking places	722	1	60	22	-22	-26	-4
Repair and maintenance	811	1	25	8	-4	-4	1
Personal and laundry services	812	1	35	8	-8	-8	0
Membership associations and organization	813	0	21	6	-5	-4	0
Private households	814	0	11	2	-2	-2	0
Other Industries		0	38	5	-16	-14	-6
Government		1	81	56	-44	-48	-11
Total		**44**	**2219**	**793**	**-495**	**-480**	**23**

*The job impacts are projected for the regional economy, which includes jobs at all businesses, whether directly affected by full BARCT implementation or not.

Figure 2 presents a projected time series of job impacts over the 2018-2035 time period. Based on Abt Associate's 2014 recommendation to enhance socioeconomic analysis by conducting scenario analysis on major assumptions, staff has analyzed an alternative scenario (worst case) where the affected facilities would not purchase any control equipment or services from providers within the Basin. This is a highly hypothetical scenario in order to test the sensitivity of the previously discussed scenarios where the analyses rely on REMI's embedded assumptions about how the capital and O&M spending would be distributed inside and outside the region. In reality, utilities expenditures are paid to local utilities producers. Moreover, construction jobs related to control installation are likely to increase hiring from the local labor force. This worst-case scenario would result in an annual average of approximately 450 jobs forgone. The approximately 480 jobs forgone in 2035 represent less than 0.01 percent of total jobs in the region. It is not expected that the proposed rule amendments will create a shift from high-to-low skill jobs.

Figure 2: Projected Regional Job Impact, 2018-2035



8.1.1 Potential Health Benefits

The South Coast Air Basin is one of only two "extreme" non-attainment areas in the nation that have not reached the federal 8-hour ozone standard. Ground-level ozone, or smog, forms when volatile organic compounds (VOC) photochemically react with nitrogen oxides (NOx) in the presence of sunlight. Encompassing a major swath of Southern California, the South Coast Air Basin is among the most densely populated areas nationwide, with about 13 million cars, trucks, and other vehicles operating on its extensive network of highways and roads.[22] The amount of pollutants produced by modern urban life and industrial activities, combined with Southern California's year-round sunny weather, all contribute to the high concentrations of ground-level

[22] According to estimates provided by the California Department of Motor Vehicles, there were a total of 13.7 million registered vehicles in Los Angeles, Orange, Riverside, and San Bernardino counties for the period of January 1 to December 31, 2013. (https://www.dmv.ca.gov/portal/wcm/connect/add5eb07-c676-40b4-98b5-8011b059260a/est_fees_pd_by_county.pdf?MOD=AJPERES, accessed February 18, 2015.) The South Coast Air Basin covers all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties; therefore, the total number of vehicles would have been somewhat smaller.

ozone in the area. Ozone exposure can cause immediate, adverse effects on the respiratory system and result in various symptoms such as coughing, throat irritation, chest pain, and shortness of breath. It can also inflame the lining of the lungs, and for asthma patients, it may increase the number and severity of attacks. Long-term impacts of frequent exposure to ozone may lead to permanent lung damage and increase the risk of premature death.

In addition, the South Coast Air Basin remains a non-attainment area for the federal 24- hour and annual PM2.5 standards. NOx is also a precursor to PM2.5. Exposure to high levels of PM2.5 have been shown to cause and aggravate cardiopulmonary illnesses, including heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing or difficult breathing. These outcomes result in increased absences from school and work, hospitalization, and other medical expenses. Exposure to PM2.5 is associated with premature deaths. According to recent estimates by the California Air Resources Board, elevated ambient PM2.5 levels result in approximately 4,100 premature deaths annually in the South Coast Air Basin.

The reductions in ozone and PM2.5 associated with the proposed rule amendments have the potential to reduce the mortality and morbidity incidences associated with NOx emissions.

8.1.2 Competiveness

The additional cost for the proposed rule would increase the cost of services rendered by the affected industries in the region. The magnitude of the impact depends on the size and diversification of, and infrastructure in, a local economy as well as interactions among industries. A large, diversified, and resourceful economy would absorb the impact described above with relative ease.

Changes in production/service costs would affect prices of goods produced locally. The relative delivered price of a good is based on its production cost and the transportation cost of delivering the good to where it is consumed or used. The average price of a good at the place of use reflects prices of the good produced locally and imported elsewhere.

It is projected that the manufacturing sector, where most of the affected RECLAIM facilities belong, would experience a rise in its relative cost of services by about 0.013 percent and a rise in its delivered price by less than 0.001 percent in 2022 from the implementation of the proposed amendments.

8.1.3 Job Impact by Occupation

Occupations can be grouped into five categories according to median weekly earnings (See Table A in Appendix B for more details). Group 1 has the lowest-paid occupations while Group 5 has the highest-paid occupations. Table X shows the job impact as a percentage of the baseline jobs under the proposed amendments for each occupational wage group. Median weekly U.S. wage rates for 95 occupations are obtained from the 2013 BLS Employment and Earnings. The wage rates are ranked in ascending order, and then divided into five groups. The range of occupational wage rates as listed in the Appendix B.

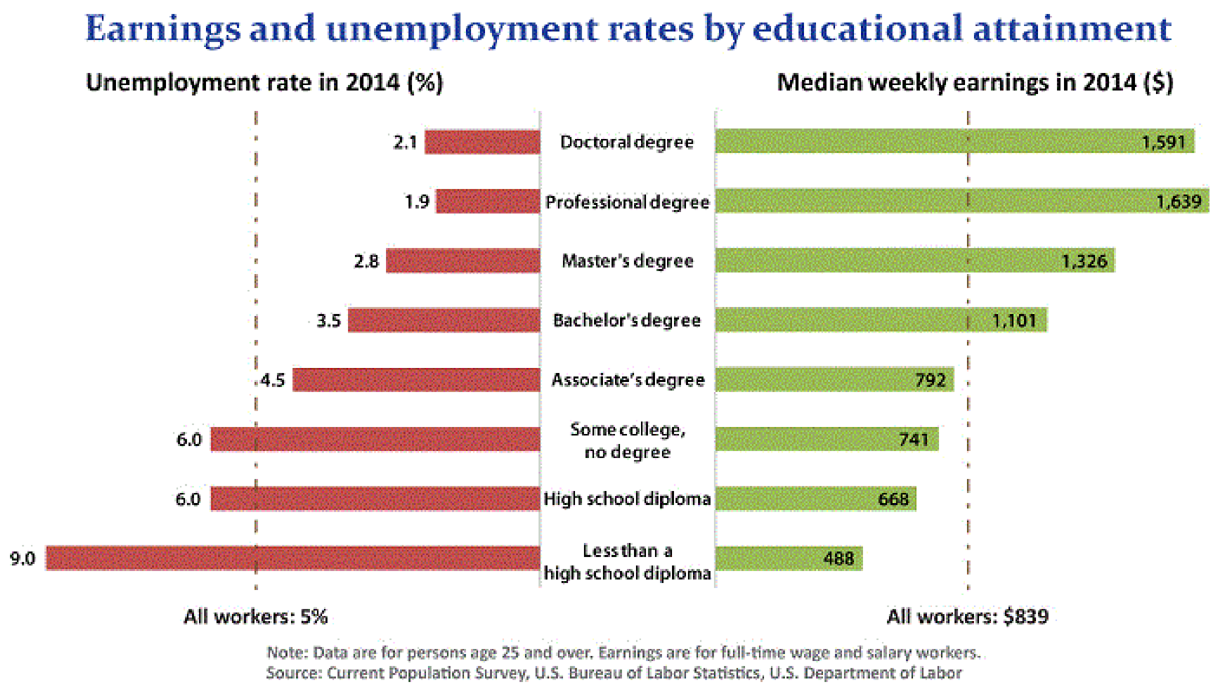
A positive figure indicates that the proposed amendments create more jobs and a negative figure means the opposite. In earlier years of the implementation of these amendments, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs proportionally forgone from the additional cost of doing business. However, as affected facilities continue to incur the amortized capital expenditures, reductions in job growth would set in, resulting in jobs forgone in later years.

For example, in 2018 through 2022, the full installation of BARCT controls is projected to result in more jobs created with respect to the baseline for all occupational groups. As shown in Table 19, however, proportionately fewer jobs would be foregone (e.g., in 2030 and 2035) for lower skilled than higher skilled jobs. For the purpose of this analysis, staff assumed lower skilled jobs as those jobs that do not require a bachelor's degree which according to the 2014 Bureau of Labor Statistics would have weekly earnings of about $1,100 per week. Similar job impacts by occupational group would have occurred under command-and-control regulations as they would also require the full installation of BARCT controls.

Table 19:
Job Impact of the Proposed Amendments by Occupational Wage Group by Year

Group	Median Weekly Earnings*	% Impact from Baseline					No. of Occupations
		2018	2021	2022	2030	2035	
1	$236 - $480	0.0002%	0.0104%	0.0033%	-0.0032%	-0.0032%	19
2	$481 - $619	0.0003%	0.0152%	0.0046%	-0.0051%	-0.0049%	19
3	$620 - $767	0.0009%	0.0453%	0.0173%	-0.0065%	-0.0054%	19
4	$768 - $980	0.0003%	0.0119%	0.0045%	-0.0040%	-0.0040%	19
5	$990 - $1738	0.0004%	0.0193%	0.0069%	-0.0049%	-0.0047%	19

*Source: Employment and Earnings. Bureau of Labor Statistics. (See http://www.bls.gov/emp/ep_chart_001.htm.)



According to the 2014 California State Board of Equalization, total gasoline sales in California were 14.57 billion gallons, of which the region's share is estimated to be 46 percent. The annual compliance cost of refineries due the proposed amendments, if fully passed on to gasoline consumers, would result in a gasoline price increase of up to 0.8 cents per gallon in the four-county area.[23] Gasoline produced by refineries within SCAQMD is also consumed in a larger region including other parts of California and areas in neighboring states (e.g. Nevada and Arizona), therefore, the actual added cost is expected to be lower than the stated amount. It should be noted that due to possible outside competition in the gasoline market, refineries may not be able to pass on the full cost of the proposed amendments to consumers. However, it should be noted that due to clean air regulations, the gasoline blends sold in this region are different from those permitted in other parts of the country. Therefore, any outside competition, if any, is expected to be very limited.

8.1.4 Rule Adoption Relative to the Cost Effectiveness Schedule

On October 14, 1994, the Governing Board adopted a resolution that requires staff to address whether rules being proposed for adoption are considered in the order of cost- effectiveness. The 2012 AQMP ranked, in the order of cost-effectiveness, all of the control measures for which costs were quantified. It is generally recommended that the most cost- effective actions be taken first.

The proposed amended rules implement control measure CMB-01 (Additional Reductions for

[23] The rate of 46 percent was applied to the state's total of 14.57 billion gallons sold to get the Basin's share of 6,702 million gallons sold. Dividing the average annual cost of the proposed amendments ($52 million) by 6,702 million gallons will result in $0.008 or (0.8 cents/gallon) increase in gasoline price.

NOx RECLAIM) in the 2012 AQMP. The cost effectiveness of this measure (Phase II) was estimated to be $16,000 per ton of NOx reduced. This measure was ranked 8th among all the SCAQMD control measures for stationary sources in terms of cost-effectiveness in the 2012 AQMP.

8.1.5 Incremental Cost Effectiveness

The annualized BARCT costs for the Proposed Rule Amendments and Alternative 3—Industry Proposal—are shown in Table 21 below. Alternative 3 will result in 5.23 less emissions reductions than the Proposed Rule Amendments (8.77 tpd vs. 14 tpd). The incremental cost of achieving the additional 5.23 tpd is taken as the difference in cost between the Proposal and Alternative 3, which is calculated by converting annualized BARCT costs into PWV 2014 dollars. The incremental cost-effectiveness for achieving the additional 5.23 tpd of NOx reductions is therefore $17,000/ton.

8.2 Impact of CEQA Alternatives

Five alternatives to the proposed amendments were developed for the CEQA analysis associated with this proposal. This section provides an assessment of the possible different socioeconomic impacts resulting from these alternatives. Table 19 below summarizes the proposed shave for each affected source category. Alternative 1 (Across the Board), Alternative 2 (Most Stringent), Alternative 3 (Industry Approach), Alternative 4 (No Project), and Alternative 5 (Weighted by BARCT Reduction Contribution for all Facilities and Investors). The primary components of the proposed alternatives that have been modified are the source categories that may be affected, and the manner in which compliance with the proposed NOx BARCT emission limits would be achieved. After further analysis, staff determined Alternatives 3 and 4 do not comply with state law.

Table 20: Proposed Amendments and CEQA Alternatives

	Proposed Amendments	**Major Refineries/ Investors**	**Non-Major Faciliti**	**Electricity generating Facilities**	**Remaining Facilities**
Staff Proposal	**Shave Applied to Facilities and Investors Holding the Top 90% of RTCs (Weighted by BARCT Reduction Contribution)** *56 total facilities, plus investors*	**66%** ***(9 Facilities)***	**49%** ***(26 Facilities)***	**49%** ***(21 Facilities)***	**0%** ***(219 Facilities)***
CEQA Alternatives					
CEQA Alternative #1	**Across the Board** *Affects all facilities and investors*	**53%**	**53%**	**53%**	**53%**

CEQA Alternative #2	**Most Stringent Approach** *Across the Board without 10% Compliance Margin*	**60%**	**60%**	**60%**	**60%**
CEQA Alternative #3	**Industry Approach** *Across the Board: Difference between previous BARCT and new BARCT*	**33%**	**33%**	**33%**	**33%**
CEQA Alternative #4	**No Project**	**0%**	**0%**	**0%**	**0%**
CEQA Alternative #5	**Weighted by BARCT Reduction Contribution** *Affects all facilities and investors*	**66%**	**36%**	**36%**	**36%**

To analyze the worst case scenarios, the CEQA analysis assumes that all other components of the project alternatives are identical to the components of the proposed project (i.e., the same control equipment); therefore, the corresponding impacts would also occur under all the alternatives except the ‘no project’ alternative. However, for the purpose of conducting socioeconomic analyses and comparing costs and job impacts under different CEQA alternatives, staff assumed that a different set of source categories would be affected under each CEQA alternative.

The analysis conducted in the ensuing subsection focuses on the 9 refineries and 11 non- refinery facilities with identified 2015 BARCT.

8.2.1 Alternative 1 – Across the Board Shave of NOx RTCs

Alternative 1 consists of an across-the-board NOx RTC shave of 14 tpd that would affect all NOx RECLAIM facilities and investors. Although the total amount of the shave is identical to the proposed project, the NOx RTC holdings would be shaved by 53 percent overall.

For the purpose of the socioeconomic analysis of the CEQA alternatives, staff assumed fewer control equipment to be installed by refineries since less reduction (53 percent vs. 66 percent) is required. To meet the proposed 53 percent shave, refinery sector needs to only reduce 4.76 out of 6.00 tpd required under the proposed project. To meet the 4.76 tpd reductions and based on the cost-effectiveness schedule, only control costs for the refinery FCCUs, gas turbines, and coke calciners are considered for the cost estimates.

On the other hand, the remaining 11 non-major facilities would need to reduce more of their current holdings relative to the proposed project (53 percent vs. 49 percent, or 3.12 vs. 2.77 tpd). Since these facilities will have their holdings reduced by 53 percent rather than the 49 percent in the proposed project, these facilities are assumed to need to purchase RTCs to meet the difference. While these facilities may purchase some RTCs, this would not be an additional cost of the program since the sellers would be paid for these RTCs. For the purpose of worst-case analysis, staff assumed these facilities will purchase 0.35 (3.12 tpd - 2.77 tpd = 0.35 tpd) tpd of RTCs at a price of $22,499 per ton (i.e. the Proposed Amended Rule 2002 trigger), irrespective of the projected demand and supply of NOx RTC and how the market would behave under this alternative shave.

8.2.2 Alternative 2—Most Stringent Shave of NOx RTCs

Alternative 2 consists of the most stringent approach by applying an across-the-board NOx RTC shave of 15.87 tpd. Alternative 2 would affect all RECLAIM facilities and investors, but without including the 10 percent compliance margin or the BARCT adjustment for refinery equipment. Under Alternative 2, the NOx RTC holdings would be shaved by 60 percent overall. Under Alternative 2, the total shave of 15.87 tpd is greater than the 14 tpd shave that is contemplated by the proposed project. In addition, the distribution of the shave under Alternative 2 would reduce the NOx RTC holdings differently than the proposed amendments: 60 percent reduction would be applied to all 275 NOx RECLAIM facilities and investors.

For the purpose of the socioeconomic analysis of the CEQA alternatives, staff assumed less control equipment to be installed by refineries since less reduction (60 percent vs. 66 percent) is required. To meet the proposed 60 percent shave, the refinery sector needs to only reduce 5.34 tons out of 6.00 tons required under the proposed project. To meet the 5.34 tons reductions and based on the cost-effectiveness schedule, only control costs for the refinery FCCUs, gas turbines, coke calciners, and boilers/heaters are considered for the cost estimates.

On the other hand, the remaining 11 non-major facilities need to reduce more relative to the proposed project (60 percent vs. 49 percent or 3.39 vs. 2.77 tpd). Since these facilities will have their holdings reduced by 60 percent rather than the 49 percent in the proposed project, these facilities are assumed to need to purchase RTCs to meet the difference. For the purpose of the worst-case analysis, staff assumed these facilities to purchase 0.62 tpd of RTCs at a price of $22,499 per ton, irrespective of the projected demand and supply of NOx RTCs and how the market would behave under this alternative shave.

8.2.3 Alternative 3 – Industry Approach

Alternative 3, an approach that has been proposed by industry representatives does not comply with state law because it does not meet the definition of BARCT as the maximum degree of reductions achievable, taking into account economic and other impacts (HS&C 40406). This proposal consists of an across the board NOx RTC shave of 8.77 tpd that would affect all RECLAIM facilities and investors. The total amount of shave would be lower than the 14 tpd shave that is contemplated by the proposed project. Under Alternative 3, the NOx RTCs held by all RECLAIM facilities and investors would be shaved by 33 percent. Since there are unused RTCs in the system, it is very likely that facilities would first give up most of their unused credits and install additional controls as needed to reach the total 8.77 tons. However, the analysis assumes that facilities would install controls to reach the required 33 percent reduction to provide a conservative estimate of costs.

For the purpose of the socioeconomic analysis of the CEQA alternatives, staff assumed less control equipment to be installed by refineries since less reduction (33 percent vs. 66 percent) is required. To meet the proposed 33 percent shave the refinery sector needs to only reduce 2.97 tons out of 6.00 tons required under the proposed project. To meet the 2.97 tons reductions and based on the cost-effectiveness schedule, only control costs for the refinery gas turbines are included for the cost estimates.

As in the refinery sector, the remaining 11 non-major facilities would have fewer holding reductions relative to the proposed project (36 percent vs. 47 percent or 1.94 vs. 2.77 tons/day). To meet the 1.94 tons reductions and based on the cost-effectiveness schedule, only control costs for the sodium silicate furnace, ICE engines, container glass furnace, and metal heat furnaces are considered for the cost estimates.

8.2.4 Alternative 4—No Project

Alternative 4 is the "No Project" approach such that no NOx RTC reductions would be applied to any RECLAIM facility or investor. CEQA requires the specific alternative of No Project to be evaluated even though it also does not comply with state law for the same reason as Alternative 3. A No Project Alternative consists of what would occur if the proposed amendments were not approved. The net effect of not amending Regulation XX to reduce the available RTCs on the market would be a continuation of the 2005 amendments to the NOx RECLAIM program

Under Alternative 4, existing Regulation XX would remain as currently written. Additional NOx reductions are not anticipated because the current level of NOx allocations is projected to exceed NOx emissions. Consequently, no additional cost is expected from Alternative 4 and no other socioeconomic impacts are foreseen.

8.2.5 Alternative 5—Weighted by BARCT Reduction Contribution

Alternative 5 consists of an across the board NOx RTC reduction of 14 tpd that would affect all NOx RECLAIM facilities and investors. Although the total amount of shave is identical to the proposed project, the NOx RTC reductions under this alternative would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. As such, NOx RTC holdings for major refineries and investors would be shaved by 66 percent and the NOx RTC holdings for non-major refineries and all other facilities would be shaved by 36 percent.

For the purpose of the socioeconomic analysis of the CEQA alternatives, staff assumed the same control equipment to be installed by refineries as the proposed project since the same reduction (66 percent) is required. To meet the proposed 36 percent shave, the remaining 11 non-major facilities need to reduce less relative to the proposed project (36 percent vs. 47 percent or 2.12 vs. 2.77 tpd). Based on the cost-effectiveness schedule, only control costs for the sodium silicate furnace, ICE engines, container glass furnace, and gas turbines are considered for the cost estimates.

Table 21 presents a comparison of the alternatives in terms of annual average cost and jobs forgone. This table assumes that, under Alternatives 1 and 2, facilities would buy unused RTCs at a greater rate than in the proposed project in lieu of installing more expensive controls. Therefore, costs are lower but actual emission reductions are also lower than from the proposed project.

Table 21: Average Annual Costs and Job Impacts by CEQA Alternative For 9 Refineries and 11 Non-Major Facilities

CEQA Alternatives	BARCT Cost In $ Millions (annualized using a 4 percent discount rate)	Jobs	Amount of RTC Credits Removed from Market (Tons/day)
Proposed Amendments	$61.59	+23	14
Alternative 1	$45.83	-76	14
Alternative 2	$55.00	-83	15.87
Alternative 3	$9.40	-30	8.77
Alternative 4	$0	0	0
Alternative 5	$60.23	+34	14

The proposed project has the highest cost but the second to highest positive job impact, due to increased labor demand for the full, instead of partial, installation of BARCT equipment. Alternative 4 serves as a benchmark against which other alternatives were evaluated. Of the four remaining alternatives, Alternative 3, which does not comply with state law, has the lowest cost ($9.40 million) because it is expected to induce the least number of BARCT equipment to be installed; however, it would result in an average of about 30 jobs foregone annually. This alternative excludes controls on FCCU and SRU/TGUs, boilers/heaters, and coke calciner units at refineries and hence would avoid potential costs, but also the jobs that could be potentially created due to additional expenditure on these controls. In addition, this alternative would achieve fewer emission reductions from the 20 BARCT facilities.

Alternatives 1 and 2 would cost less than the proposed amendments, yet would experience much more negative job impacts (about 80 annual jobs forgone). This is due to less BARCT installation spending in the refinery sector relative to the 11 non-refinery facilities and would result into negative net job impacts.

9. MARKET ANALYSIS

In addition to the potential compliance cost of control equipment installation and operation for these 20 facilities, the proposed amendments may potentially result in new or additional compliance costs for some of the 36 facilities where no control equipment was identified for installation. New costs would be the result of some facilities finding that their emissions exceed their RTC holdings post-shave. These facilities with negative balances would become net buyers and face the costs of purchasing additional RTCs to remain compliant. Additional costs would be incurred by facilities that were net buyers before the shave and would see their holdings further reduced under the proposed shave.

Along with the cost of additional credits that would need to be purchased, every unit of traded NOx RTCs could potentially become more expensive as a result of the proposed shave. In the short term, these net buyers are expected to purchase RTCs at a higher price, although RTC costs may go down in the long-term, if some (or all) of the 20 facilities with identified control equipment chose to install controls and offer surplus RTCs for sale. In addition to the potential compliance cost that would be incurred by the 36 shaved facilities with no identified control equipment, compliance costs could also be incurred by the net buyers who already exist within the remaining group of 219 facilities that are exempt from the RTC shave under the proposed rule. These facilities are expected to buy RTCs every year and would also face possibly higher RTC prices as the potential market supply decreases (at least in the short term). Under CEQA alternatives, these 219 facilities may incur even more costs from varying degrees of RTC shaves.

In order to estimate the magnitude of these market impacts, a price analysis has been conducted. To estimate the potential impact of price increases on the projected net buyers, a sensitivity analysis was conducted where prices grew from 100, 200, 300 percent, and up to $22,499/ton, which is just below the proposed amended price exceeding which the non- tradable/non-usable credits will be converted to tradable/usable NOx RTCs upon Governing Board concurrence. It should be noted that the compliance costs incurred by these projected net buyers would at the same time create monetary benefits to other RECLAIM facilities and/or investors who would be the sellers of these credits.

Finally, the monetary value of the shaved RTC holdings, which would be removed from the 56 facilities, has also been estimated. However, it should be noted that this estimated value is not considered a compliance cost as RTCs were originally allocated to RECLAIM facilities at zero cost and are not legally considered a facility's property. The results of this "value" analysis are set forth below on page 47.

9.1 Assumptions for Price Analysis

Two types of credits exist within the RECLAIM market: Discrete-year credits which are valid within the year of issuance and Infinite-Year Blocks (IYB) which are bundles that extend into perpetuity after the initial purchase year. Given that prices for discrete-year are the most reflective of actual market behavior, they form the basis of this analysis. Over the past 5 years, prices for discrete RTCs begin at about $3,000 to $4,000 per ton and eventually drop to around $1,000 per ton as the end of the year approaches. RTCs are much less expensive near the end of the year when the RTC expiration date approaches.

The base price of $3,779 per ton for discrete RTCs from January in compliance year 2015 was used for this analysis.[24] In order to capture a realistic range of increases up to the $22,500 per ton trigger, an increase of 100 percent, 200 percent, and 300 percent was applied to the base price of $3,779 per ton. These values were then aggregated into their yearly totals. Table 22 summarizes

[24] This price represents a 12-month rolling average which is calculated to smooth out short-term fluctuations and present long-term trends. For more information see: http://www.aqmd.gov/docs/default- source/reclaim/nox-rolling-average-reports/12-mo-rolling-avg-price-comp-yrs-2014-15-nox-rtcs---july- 2015.pdf?sfvrsn=6

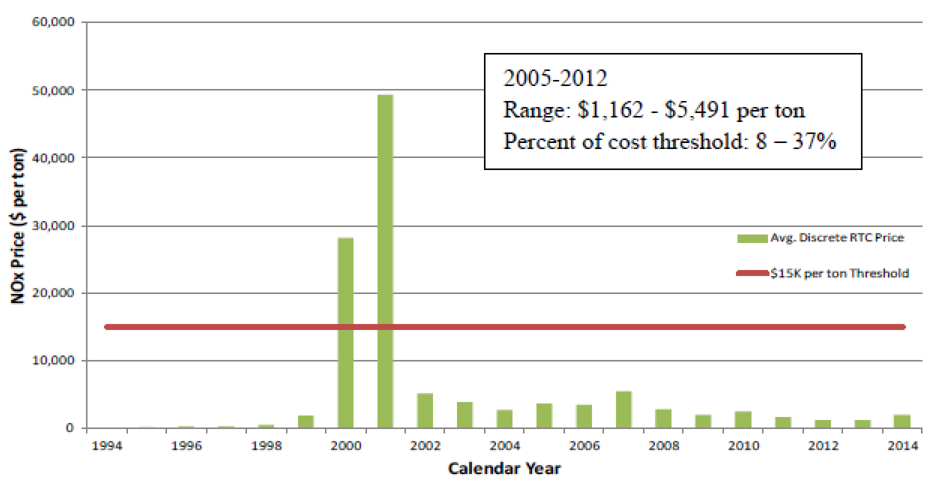
the results below.

Table 22: Estimates of RTC price increase

Type	Market price	100 percent Increase	200 percent Increase	300 percent Increase	Proposed Amended Rule 2002 Price Trigger
Discrete Ton	$3,779	$7,558	$11,337	$14,999	$22,499

These cost assumptions are conservative given historical trends in the marketplace. Since the adoption of Regulation XX, there have been a number of amendments to the RECLAIM rules, including BARCT reassessments for NOx in 2005. As a result of the January 2005 amendment, NOx RTCs were reduced by 7.7 tpd (accounting for approximately 22.5 percent of the total RTC holdings at that time) uniformly across the then 281 RECLAIM facilities. This reduction was implemented in phases: 4 tpd in 2007 and an additional 0.925 tpd in each of the following 4 years. Figure 3 shows discrete RTC prices for compliance years 1994 to 2013, reflecting the fact that the NOx reductions specified by the January 2005 amendment did not cause major RTC price spikes.

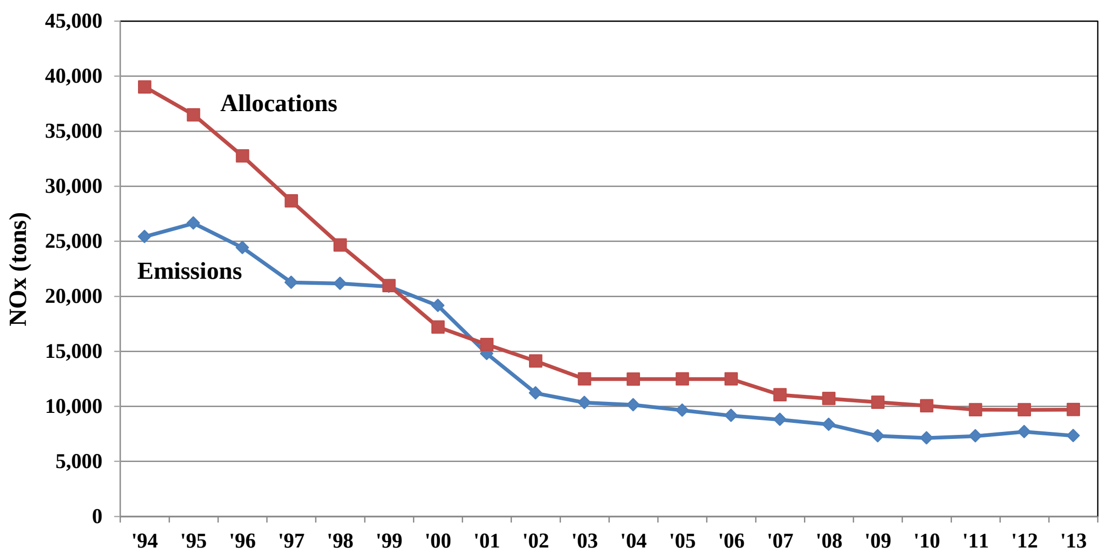
Figure 3: NOx Discrete Prices vs. Threshold



Additionally, since the RECLAIM program began in 1994, actual NOx emissions have consistently been well below total RTC holdings (except during California's energy crisis in 2001). Figure 4 shows how, despite past changes in the market's structure, there were sufficient amounts of NOx RTCs available to allow for expansion and modification by RECLAIM facilities. In drafting the proposed rule, staff added a 10 percent compliance margin to the projected 2023 emissions by RECLAIM facilities at the proposed 2015 BARCT levels and an additional 0.85 tpd to account for uncertainties in the BARCT analysis and base year activity level adjustments. Given this historical trend and staff's efforts to structure the rule effectively, the remaining NOx RTC holdings after the proposed shave is fully phased in are not expected to drop below actual total NOx emissions, even with less than the full implementation of control equipment. Large price spikes are not expected unless some facilities hoard large quantities of RTCs, thus constricting the supply such that prices are not set competitively.

In order to identify the potential buyers of NOx RTCs in 2023 and subsequent years, staff assumed that the only change in RTC allocations would be the proposed shave. Regarding future emissions, staff started with the actual 2011 NOx emissions among existing emission sources, except electricity generating facilities for which their 2012 emissions were used as in the Revised Draft Staff Report. Sector-specific growth factors were then applied to project NOx emissions at each facility in 2023. By doing so, staff assumes in the analysis that emissions at each facility would grow at the same rate; however, it is possible that emissions would grow more at facilities with surplus NOx RTC holdings and less at facilities who already need to purchase NOx RTCs annually from the market. Therefore, the projected incremental compliance cost reported in this section can be considered as a conservative estimate. In the meantime, potential increases in compliance cost due to higher RTC prices was not explicitly considered for new and modified sources, nor for the required holdings beyond actual emissions for the electricity generating facilities. Staff did not explicitly consider increases due to higher RTC prices for facilities with new and modified sources, given that staff cannot predict the number of new and modified sources and the amount of RTCs needed for them. However, they are implicitly taken into account when growth factors were applied to project future growth by industry. These projected future emissions by industry-wide growth factors may be able to capture at least a portion of the incremental compliance costs potentially incurred by these facilities.

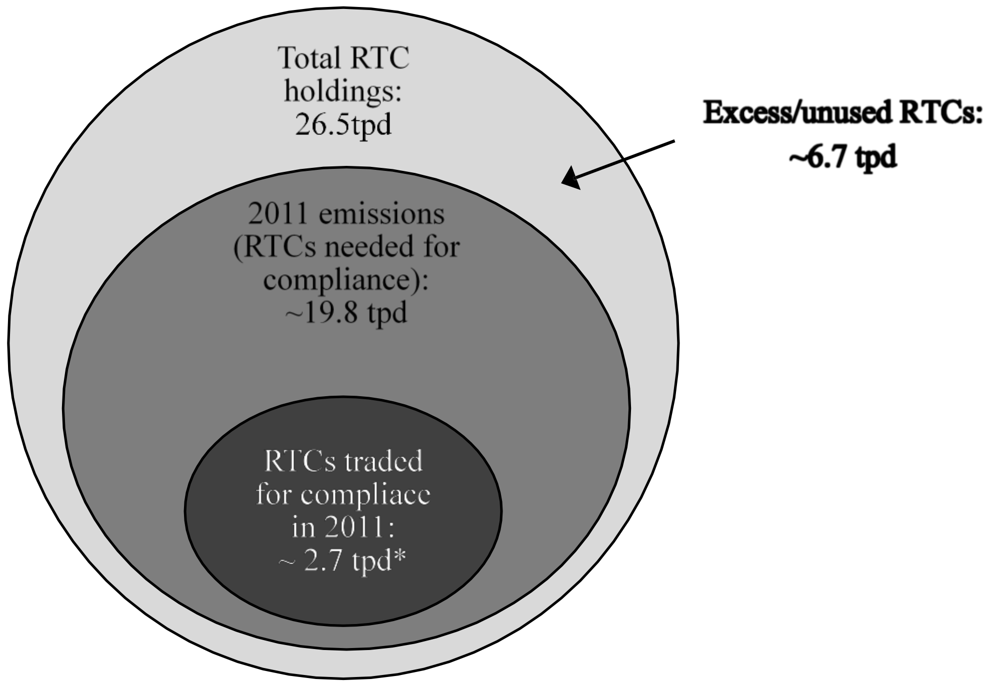
Figure 4: Audited Emissions and RTC Holdings



9.2 Understanding the Impact of the First 4 tpd Shave

Under the proposed rule amendments, 4 tpd of NOx RTCs would be removed from the NOx RECLAIM program in 2016, and this analysis assumed that no new BARCT control equipment would be installed in that year. Based on 2011 data, there existed a wide margin between the overall NOx RTC holdings and actual emissions. As illustrated in Figure 5, a total of about 6.7 tpd were unused and considered as excess NOx RTC credits. Moreover, in 2011, only 2.7 tpd of NOx RTCs were traded in the market directly for the purpose of regulatory compliance, while 6.7 tpd of excess RTCs remained unused. Therefore, even with no assumed BARCT installation in 2016 (thus, no additional credits expected to be released into the market for trading), it would be unlikely that NOx RTC prices would skyrocket after the first 4 tpd of NOx RTCs are shaved. To be conservative, however, the following analysis will examine different price scenarios to evaluate the potential cost impact in the first year of the proposed shave.

Figure 5: Distribution of RTCs in NOx RECLAIM Market, 2011



*RTCs traded for compliance was calculated for each NOx RECLAIM facility by: 1) subtracting 2011 RTC holdings from 2011 NOx emissions and 2) summing up the negative balance, which is equivalent to the amount of facility emissions that a facility did not have RTC holdings for. Among the approximately 2.7 tpd RTCs traded for compliance in 2011, close to 60 percent was purchased by the 9 refineries and 11 non-refinery facilities with identified control equipment.

9.3 Potential Compliance Cost for Net Buyers: 36 Affected Facilities

For the first shave of 4 tpd in 2016, up to 7 of the 36 shaved facilities (3 existing net buyers and 4 new net buyers) could have their emissions exceed their RTC holdings, based on 2013 emission data. These 7 facilities are expected to purchase up to 0.45 tpd of NOx RTCs annually from the market, up from 0.32 that are currently needed. If RTC price remains constant following the shave, the facilities would incur costs of about $0.18 million for the additional 0.13 tpd of NOx credits needed (0.45 tpd - 0.32 tpd = 0.13 tpd). If the price increases by 100 percent, 200 percent, 300 percent or up to $22,499/ton, then these facilities would incur a higher cost of $0.81 million/$1.43 million/$2.04 million/$3.27 million respectively, not only for the cost of additional RTCs needed due to the initial 4 tpd shave but also for the higher price of the 0.32 tpd already needed before the shave.[25]

As a result of the 14 tpd shave fully phased-in in 2022, up to 15 of the 36 facilities (6 existing net buyers plus 9 new net buyers) are expected to have their 2023 emissions exceed their projected RTC holdings, unless they make operational changes at their facility or purchase RTCs.[26] When CEQA alternatives are considered, the number of facilities that fall into this group of net buyers ranges from 6 to 17.

Under the proposed shave, these 15 facilities are expected to need to purchase up to 1.52 tpd of NOx RTCs annually from the market, up from 0.97 tpd that are currently needed. If RTC price remains constant following the shave, the facilities would incur costs of $0.76 million for the additional 0.55 tpd of NOx RTCs needed (1.52 tpd –0.97 tpd = 0.55 tpd). If the price increases by 100 percent, 200 percent, 300 percent and up to $22,499/ton trigger, then these facilities would incur a higher cost of $2.85/$4.94/$6.97/$11.13 million respectively, not only for the cost of additional RTCs needed due to the shave but also for the higher price of 0.97 tpd already needed before the shave. By comparison, these potential compliance costs could represent up to 16 percent of the overall annual compliance cost associated with control installation.[27] However, these costs are not additional to the overall cost of the proposed shave because increased costs to RTC buyers are canceled out by increased gains to RTC sellers.

Under the CEQA alternatives, these 36 facilities would be subject to different shaves and result in different projected amounts of RTCs that would needed to be purchased. Under the CEQA alternatives, the potential compliance costs for some of these 36 facilities would range between $0 and $14 million, depending on the price differential assumed. It is assumed these funds would remain in the local economy as they flow to other RECLAIM holders who are selling RTCs. Table 23 summarizes the potential compliance cost for the proposed rule amendment and the CEQA alternatives for this group of facilities under different price scenarios.

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[25] The formula used for calculating this cost is: [pre-shave RTC purchase necessary for compliance*(post- shave RTC price – pre-shave RTC price) + (post-shave RTC purchase necessary for compliance - pre-shave RTC purchase necessary for compliance)*post-shave price]*365 days.

[26] 2023 emissions are calculated by applying a growth factor of 0.87 to the 21 electricity generating facilities' 2012 actual emissions and 1.10 growth factor to the remaining 16 facilities' 2011 actual emissions. See Revised Staff Report for emissions projections.

[27] To arrive at this percent increase, the total compliance cost of full BARCT installation was converted to 2015Q1 dollars using the Marshall & Swift Indices.

Table 23: Annual Price Increases for Net Buyers for 36 Facilities from 2023 onwards

36 Facilities	Number of Net Buyers	Amount of RTCs to be purchased (TPD)	Estimated Incremental Increases in Cost				
			Current Market Price (Thousands)	100 percent differential (Thousands)	200 percent differential (Thousands)	300 percent differential (Thousands)	$22,499 (Thousands)
Proposed Rule Amendments	15	1.52	$760	$2,850	$4,940	$6,970	$11,130
Alternative 1	17	1.63	$910	$3,160	$5,410	$7,580	$12,040
Alternative 2	17	1.82	$1170	$3,690	$6,200	$8,630	$13,620
Alternative 3	11	1.25	$380	$2,110	$3,830	$5,500	$8,920
Alternative 4	6	0.97	$0	$0	$0	$0	$0
Alternative 5	12	1.30	$460	$2,260	$4,060	$5,800	$9,370

9.4 Potential Compliance Cost for Net Buyers: 219 Facilities

Among the 219 facilities that would be exempt from the proposed shave, 102 facilities were estimated to have purchased NOx RTCs to remain in compliance according to the projected 2023 emissions and the projected RTC holdings in 2023. These 102 facilities represent 13 different industries with half belonging to the manufacturing sector (NAICS 31-33). In 2013, this group's NOx RTC holdings fell short of its actual NOx emissions by roughly 0.81 tpd, and this gap is expected to widen to 1.33 tpd in 2023 due to industry growth.[28] Therefore, some facilities have needed and will continue to need to purchase RTCs from the market to ensure they have sufficient RTCs to cover their emissions.

Under the proposed rule amendments, the 219 facilities would not be shaved. If the price of NOx RTCs remains unchanged from the current market price, no additional compliance cost would be incurred. If, however, the price increases by 100 percent, 200 percent, or 300 percent and up to $22,499/ton trigger, then these facilities would have to pay an additional $1.84/$3.67/$5.45/$9.6 million respectively in order to be compliant. By comparison, these potential compliance costs could represent up to 13 percent of the overall annual compliance cost associated with control installation.[29] However, these costs are not additional to the overall cost of the proposed shave because increased costs to RTC buyers are canceled out by increased gains to RTC sellers.

Under the CEQA alternatives, these 219 facilities would be subject to different shaves and the projected amount of RTCs needed to be purchased would increase as a result. The potential compliance cost under these alternatives would range between $0 and $17 million annually, depending on the price differential assumed. It is assumed these funds would remain in the local economy as they flow to other RECLAIM holders who are selling RTCs. Table 24 below summarizes the potential compliance cost for the proposed rule amendment and the CEQA alternatives for this group of facilities, under different price scenarios.

[28] 2023 emissions are calculated by applying a growth factor of 1.3 to each of the 210 facilities' 2011 actual emissions.
[29] See footnote 25.

Table 24: Annual Price Increases for Net Buyers in 219 Facilities Group from 2023 onwards

219 Facilities	Number of Net Buyers	Amount of RTCs to be purchased (TPD)	Estimated Incremental Increases in Cost				
			Current Market Price (Thousands)	100 percent differential (Thousands)	200 percent differential (Thousands)	300 percent differential (Thousands)	$22,499 (Thousands)
Proposed Rule Amendments	102	1.33	$0	$1,840	$3,670	$5,450	$9,100
Alternative 1	146	2.19	$1,190	$4,210	$7,240	$10,170	$16,170
Alternative 2	150	2.34	$1,390	$4,610	$7,830	$10,960	$17,350
Alternative 3	127	1.80	$650	$3,140	$5,620	$8,030	$12,960
Alternative 4	102	1.33	$0	$0	$0	$0	$0
Alternative 5	133	1.87	$740	$3,330	$5,910	$8,410	$13,530

9.5 REMI Job Impacts of RTC Purchases

Regarding the incremental compliance cost that could potentially be incurred by the NOx RECLAIM facilities that do not have cost-effective controls identified by the 2015 BARCT analysis, the associated job impacts in the regional economy have been estimated under various scenarios of discrete NOx RTC prices. In addition to the incremental costs incurred by RTC buying facilities, the transactions will at the same time create financial gains for the RTC sellers. In order to project future NOx RTC sales by industry, staff used the 2010-2014 NOx RTC transaction data to arrive at an average percent distribution of sales by industry.

If prices remain the same, little job impact is expected due to the proposed amendments. If the average annual discrete NOx RTC prices increase to $22,499/ton and none of the affected facilities pursue any other more cost-effective compliance options, then about 40 jobs on the net would be foregone annually between 2023 and 2035. However, this latter price scenario is unlikely to occur, particularly if the 9 refineries and 11 non-refinery facilities install identified cost-effective controls, which would then either decrease the market demand or increase the market supply of NOx RTCs by these facilities.

It should be noted that all CEQA alternatives except Alternative 4 (No Project) would result in a more negative job impact—up to about 60 jobs foregone on an average annual basis if the average annual discrete NOx RTC prices increase to $22,499/ton and none of the affected facilities pursue any other more cost-effective compliance options—than the proposed amendments. This is mainly because, unlike the proposed amendments, Alternatives 2, 3 and 5 would not exempt from the shave the 219 facilities that tend to be smaller and use more labor-intensive production technologies than, for example, those used by the refineries.

The table below illustrates the job impacts on all facilities needing to purchase additional RTCs.

Table 25: Average Annual Jobs Foregone as a Result of RTC Purchases

All Facilities	**Average Annual Job Impact (2023-2035)**				
	Current Market Price	**100 percent increase**	**200 percent increase**	**300 percent increase**	**$22,499**
Proposed Rule Amendments	+1	-6	-14	-21	-36
Alternative 1	-2	-13	-25	-36	-58
Alternative 2	-2	-13	-24	-35	-57
Alternative 3	-2	-13	-24	-35	-57
Alternative 4	0	0	0	0	0
Alternative 5	-2	-13	-24	-35	-57

9.6 Value of Shaved Excess RTCs

SCAQMD staff believes the proposed shave of 14 tpd is necessary in order to induce the 20 facilities with identified control equipment to upgrade their control equipment and achieve programmatic BARCT equivalency. This is especially likely given that about 60 percent of the 2.7 tpd of RTCs traded for compliance in Compliance Year 2011 were made by the 20 affected facilities.

Some stakeholders commented that the shave should be divided into 8.79 tpd[30] of a BARCT shave and 5.21 tpd of an excess RTC shave. Staff does not agree with this division because 14 tpd of NOx RTC shave is necessary to induce a BARCT-equivalent level of *actual* NOx emission reductions. Moreover, at the outset of RECLAIM, RTCs were allocated to RECLAIM facilities free of charge, yet they now have value to the facilities as a commodity that can be bought and sold. While RTCs have value, they are not a property right. The proposed amendments to RECLAIM will reduce the number of RTCs. Since there was no cost associated with allocated RTCs for a facility, there should be no financial loss to the RECLAIM universe as the SCAQMD retires them. Staff's analysis of the RECLAIM data revealed that only 3.33 tpd out of the proposed 14 tpd shave would affect additional acquisitions of NOx RTCs that were used to expand a facility's NOx RTC holdings beyond the original free-of-charge allocations. These 3.33 tpd of NOx RTCs are spread across 24 RECLAIM facilities, and more than three quarters of these shaved credits would be concentrated in the refinery sector. If a value is estimated for the 3.33 tpd of shaved credits, it is $4.6 million annually, applying the base price of $3,779 per ton.

However, the choice between additional RTC purchase and emission control installation is solely a business decision to comply with RECLAIM requirements, and the decision to purchase RTCs in lieu of installing emission controls is most likely made to minimize overall compliance cost. Therefore, it is expected to generate an expected stream of cost-savings afforded only by the RECLAIM program and not available under command-and-control. Therefore, any RTC investment loss should not be considered as a compliance cost to be compared to the compliance cost under command-and-control regulations (Section 11 includes further explanations on this topic). Moreover, this loss may be offset by any potential increase in RTC price due to a decreased RTC supply, which would subsequently raise the market value of a facility's remaining RTC holdings. Finally, any loss of "value" of shaved RTCs cannot be compared to command and control, because in that case, there are no RTCs and thus no similar "value" was ever created.

10. NEW REVISIONS TO THE PROPOSED RULE AMENDMENTS

The Revised Draft Socioeconomic Report (released on October 6, 2015) was based on the version of the rules presented at the July 22, 2015 Public Workshop. Since then, there have been revisions made to the Proposed Rule Amendments. The revisions that were already incorporated in the Revised Draft Staff Report (released on October 6, 2015) have been reflected in the analysis presented in the previous sections. The potential socioeconomic impacts of the newer revisions are discussed below.

[30] As of the Revised Draft Staff Report released on November 5th, this number is now 8.77.

10.1 Option to Exit for Electricity Generating Facilities

Under the Proposed Amendments to Rule 2001, an electricity generating facility (EGF)—excluding cogeneration plants—would be allowed to exit the RECLAIM program, provided that at least 99 percent of the facility's NOx emissions for the most recent three full compliance years are from equipment that meets current BACT or BARCT for NOx. If an EGF decides to opt out from RECLAIM, it would need to surrender a pre-defined amount of NOx RTCs to be retired from the NOx RTC market. For existing EGF RECLAIM facilities as defined by the rule, the amount to be surrendered would be equivalent to the amount of NOx RTC holdings as of September 22, 2015, as adjusted by the proposed shaves; for other EGFs, the amount would be equivalent to the quantity required to be held by the facility pursuant to Rule 2005 – New Source Review.

Since the ability to exit RECLAIM is an option, it will be a business decision made by an EGF to exit RECLAIM, and therefore, it can be reasonably assumed that the business decision to exit the program would generate potential cost-savings for the facility; therefore, such a facility is not expected to experience any adverse economic impact due to this proposed rule amendment. However, due to the proposed provisions that a pre-defined amount of NOx RTCs shall be surrendered and retired from the market, this proposed rule amendment could potentially reduce the market supply of NOx RTCs. It should be noted that, while the 21 EGFs together hold more than 20 percent of the current NOx RTCs (or 5.63 tpd as of September 22, 2015), only a very small percentage of these holdings are sold on the NOx RECLAIM market, either as IYB or Discrete NOx RTCs.

To assess the potential impact on both the IYB and Discrete NOx RTC market, staff analyzed the NOx RTC transactions occurring during the period from 2010-2014. To begin, staff eliminated any transaction that did not have a positive market value (which could be due to a business's internal transfers or equal-value swap trades), and therefore might not have reflected real market supply and demand. Infinite-Year-Block (IYB) NOx RTCs sold by any operating EGFs over the five-year period represented less than 0.00001 percent of total IYB NOx RTCs traded in this market. As a result, little impact from EGF opt-out is expected for the IYB market.

Less than half of the EGFs have consistently sold RTCs in the discrete credit market over the past five years. As shown in the table below, during 2010-2014, these EGFs sold an annual average of nearly 1.4 tpd of NOx RTCs to help satisfy the market demand for discrete year NOx RTCs. Many of these facilities would be subject to a 49% shave under the proposed rule amendments and will no longer have that much surplus NOx RTCs for sale on the market. Therefore, in the worst-case scenario if all EGFs decide to exit RECLAIM, the post-shave market supply of NOx RTCs would be decreased by 0.216 tpd, once they have all opted out.[31] The decrease per se may exert an upward pressure on the discrete NOx RTC prices. (The estimated incremental compliance cost associated with market price increases of discrete NOx RTCs can be found in Section 9.) It is also possible that these EGFs choose to opt out during the 2016-2022 period, thus removing more NOx RTCs from the market than would occur after full shave implementation in 2022. Note that EGFs opting-out may also decrease demand for RTCs. Nonetheless, if that happens and credit prices increase

[31] The total projected surplus NOx RTCs for all operating EGFs in 2023 are estimated to be up to 1.5 tpd. However, staff does not expect this full amount of surplus credits would be offered for sale in the NOx RTC market, as a large share of these credits are held by EGFs that typically do not sell their surplus NOx RTCs.

to the level as specified by the Rule 2002 price trigger, the non-tradable/non-usable credits would then be converted to tradable/usable credits, which would be sufficient to temporarily offset the decrease in NOx RTC supply due to any EGF opt-out. (As shown above, the decrease resulting from EGFs opting out is expected to be less than 1.4 tpd while the amount of potential credit conversion would be at least 2 tpd.)

Table 26: Potential Decrease in the Market Supply of Discrete NOx RTCs due to EGF Opt-Out

Electricity Generating Facility Selling NOx RTCs during 2010-2014 (excl. Cogeneration)	Average Annual NOx RTC Sale (tpd)	Proposed Total Shave (tpd)	Estimated Post-Shave Market Supply (tpd) = Min (0, Average Annual NOx RTC Sale - Proposed Total Shave)
A	0.353	0.363	0.000
B	0.347	0.176	0.171
C	0.264	0.330	0.000
D	0.219	0.196	0.023
E	0.087	0.160	0.000
F	0.049	0.077	0.000
G	0.044	0.120	0.000
H	0.017	0	0.017
I	0.006	0	0.006
Total	**1.385**		**0.216**

In a letter dated November 17, 2015, WSPA stated that the Socioeconomic Assessment "does not consider whether such a supply constriction [from EGF opt-out] might actually impair regional economic activity due to a lack of available RTCs. Rather, it assumes that RTC supply will be available at some (presumably higher) cost without providing any evidence to support that assumption." In another letter dated November 17, 2015, Southern California Air Quality Alliance on behalf of the NOx RECLAIM Industry Coalition stated that the Socioeconomic Assessment did not consider the effect of EGF opt-out on the IYB market. Staff believes that these comments are a result of misunderstandings. The analysis presented in the paragraphs above, which is a refinement of the analysis conducted in the Draft Final Socioeconomic Report, clearly represents staff's assessment of the effects of EGF opt-out on the discrete year and IYB NOx RTC market.

The WSPA comment letter dated November 17, 2015 incorrectly claimed that the Socioeconomic Report released on November 4, 2015 acknowledged that "EGFs have been significant sellers of surplus RTCs in the discrete credit market over the past five years to meet market demand; […]." While the 21 EGFs together hold more than 20 percent of the current NOx RTCs (or 5.63 tpd as of September 22, 2015), they rarely offered any IYB RTCs for sale, and are not expected to do so in the future given their NSR holding requirements and/or grid stability considerations. Less than half of the EGFs were regular net sellers of discrete NOx RTCs over the past five years, and they supplied an annual average of 1.4 tpd in total, which is about only 5 percent of the current total NOx RTC holdings. In the post-shave market (i.e., 2023 and beyond.), the estimated 0.216 tpd of remaining market supply among these facilities would account for less than 2 percent of total post-shave market holdings.

10.2 NOx RTC Price Triggers

Under the Proposed Amendments to Rule 2002, the price threshold beyond which the non-tradable/non-usable NOx RTCs would be converted to tradable/usable NOx RTCs is raised to $22,500 from $15,000, on the basis of 12-month rolling average of discrete NOx RTC prices. In order to further ensure price stability during the proposed phased-in period of 2016-2022, an additional stabilization mechanism would be put in place, which constitutes an additional price trigger of $35,000, on the basis of 3-month rolling average of discrete NOx RTC prices. This additional price trigger would assist with shortening the duration of any potential price spikes and containing the magnitude of any potential adverse economic impact on NOx RTC buyers. The estimated incremental compliance cost associated with market price increases of discrete NOx RTCs can be found in Section 9, which contains the price scenario where buyers would need to pay $22,500 per discrete ton of NOx RTC to reconcile their annual NOx emissions.

Proposed Amended Rule 2002 also contains another price trigger—$200,000 per ton (Infinite Year Block) based on the 12-month rolling average—below which the Executive Officer will report the determination to the Governing Board. As the determination is yet to be made and the provision would not be effective until 2019, it is speculative to assess any potentially resultant socioeconomic impact. Moreover, following the 2005 NOx RECLAIM amendments, none of the 51 SCRs identified in the BARCT analysis for refineries have been installed because of RECLAIM, not even in 2008 when the average IYB prices went above $200,000 (in 2008 dollars) per ton of NOx. This suggests that NOx RTC prices could have been historically too low to induce cost-effective control installation, and the 200,000 price trigger floor is conservative.

10.3 Facility Shutdowns

Since the adoption of RECLAIM, facilities which planned to shut down were not restricted from selling off their RTCs prior to facility closures. RTCs resulting from shutdowns are not subject to the best available control technology (BACT) discount that is applicable to non-RECLAIM sources.

As a consequence, staff estimated that a significant portion of the unused RTCs can be traced to the sale of pre-closure RTCs. As shown in Table 2 of this report, facility shutdowns amounted to 2.62 tpd of actual NOx emission reductions between 2006 and 2012, which was just less than two thirds of the 4 tpd actual total reductions over the same period. However, NOx RTCs that were previously held by these shutdown facilities were never removed from the market, thus exerting a downward pressure on the RTC market prices. This, in turn, has dis-incentivized the remaining NOx RECLAIM facilities from installing cost-effective control equipment or making other changes at their facilities.

Under the Proposed Amended Rule 2002, any major NOx-emitting facility (i.e., those listed in Table 7 or 8) permanently shutting down some or all equipment with emissions greater than or equal to 25 percent of the facility emissions for any quarter within the previous 2 compliance years would need to surrender NOx RTCs to be retired from the market. The amount of NOx RTCs to be surrendered would be determined by the maximum quarterly ratio of the average NOx emissions emanating from the shutdown equipment over facility-wide NOx emissions, multiplied by the facility's NOx RTC allocations.

In the Southern California Air Quality Alliance comment letter dated November 17, 2015, it was stated that an analysis should have been conducted to assess the impact of removing RTCs from the market relating to shutdowns. Also in the WSPA comment letter dated November 17, 2015, it was stated that there was no technical analysis in the Draft Final Socioeconomic Report in this topic. Since staff cannot predict which facilities may choose to shut down some or all of their permitted equipment, it would be speculative to predict the magnitude of any impact on the NOx RTC market resulting from future shutdowns. The shut-down provision would not allow large influxes of credits into the RECLAIM market because of shutdowns. However, as discussed previously, staff acknowledges that the provision of surrendering and retiring NOx RTCs from the market could potentially affect the credit market and prices. The magnitude of the potential impact would depend heavily on the usual market behavior of each facility before it decides to shut down. On the one hand, for facilities that regularly sell their surplus NOx RTCs, the provision would exert an upward pressure on NOx RTC prices. On the other hand, if the shutdown facility is a regular buyer on the NOx RTC market or does not participate in the market at all, the retirement of their NOx RTCs would have little, if any, impact on the RTC market supply. In any event, District analyses show that the unrestrained flow of RTCs from shut downs have resulted in an oversupply of RTCs so that BARCT equivalent controls are avoided.

11. COSTS OF COMMAND AND CONTROL (CAC) COMPARED TO RECLAIM

RECLAIM allows facilities to use the least costly option to remain in compliance. Unlike the command-and-control regulations where every source has to be controlled to the same emission standard, RECLAIM facilities can pursue operational changes or purchase RTCs from investors and other facilities with surplus credits in lieu of upgrading existing control equipment or installing new control equipment. This flexibility notwithstanding, RECLAIM ultimately must achieve emissions reductions equivalent to or greater than what would have been achieved under command-and-control regulations. A BARCT assessment is required by H&SC §40440 and BARCT requires actual emission reductions. Based on staff analysis, a reduction of 14 tpd of NOx RTCs is needed to induce actual emission reductions equivalent to BARCT. The 2015 BARCT analysis demonstrated that there would be an actual NOx emission reduction of 8.77 tpd from the 2011-2012 activity levels at 2015 BARCT compared to the same activity levels at 2005 BARCT. This represents 8.77 tpd reductions in actual emissions. If the overall NOx RTC holdings had closely matched the total amount of actual NOx emissions from the NOx universe, the removal of 8.77 tpd of NOx RTCs would likely induce an equivalent amount of actual NOx emission reductions. However, over the past five years, actual NOx emissions from RECLAIM facilities fell below the overall NOx RTC holdings by 21-30%, resulting in approximately 5.45-8.41 tpd of unused NOx RTCs (unused for compliance purposes). Therefore, the removal of 8.77 tpd of NOx RTCs would first eliminate some, if not all, of these excess NOx RTCs from the market and only thereafter result in actual emissions reductions. As a result, total emission reductions would be less than the BARCT-equivalent level of actual NOx emission reductions.

The problem of excess unused RTCs is illustrated by the fact that the 2005 NOx shave did not achieve 2005 BARCT levels for the RECLAIM universe. The 7.7 tpd of NOx shave adopted in the 2005 RECLAIM amendments was phased in over the period of 2007-2011; however, only about 4 tpd of actual NOx emission reductions occurred between 2006 (the year before the 2005 shave began) and 2012 (the year after the 2005 shave was fully phased in).[32] Almost two-thirds of the actual emission reductions resulted from facility shutdowns, not installation of controls or other changes at RECLAIM facilities. Therefore, as long as there are persistently unused RTCs available in the market, the RTC shave would need to be larger than the tons of emission reductions calculated for the BARCT analysis to induce an equivalent level of actual emission reductions.

The proposed phased-in shave of 14 tpd is anticipated to be able to induce sufficient emission reductions by 2023 so that the expected total NOx emissions from the RECLAIM universe in 2023 would be consistent with the projected NOx emissions in 2023 at the 2015 BARCT levels. (Please see the Staff Report for the shave methodology.)

As discussed in the Revised Draft Staff Report, staff has identified and demonstrated that technologically feasible and cost-effective control equipment are commercially available if any of the 20 facilities with identified BARCT chooses to install controls in response to the proposed shave from the NOx RECLAIM universe. The total cost of full BARCT installation was estimated to be between $728 million and $1.1 billion (present worth value in 2014 dollars). However, a RECLAIM facility is expected to retrofit an emission source only when it meets both of the following conditions: first, it does not hold sufficient RTCs to offset facility-wide emissions at the end of the compliance period; second, the cost of control installation per ton of emission reduction is lower than the expected average RTC price over the life of the control equipment.

Even if a facility finds it more cost-effective to install pollution control equipment, it still would not incur the full cost of control installation if control installation results in surplus RTCs that the facility eventually sells to offset the control installation cost. In comparison, command-and-control regulations would require, under all circumstances, that this same facility install the control equipment and incur the full cost of control installation. As a result, total costs to install controls under RECLAIM will always be equal to or less than under command and control. Under command and control, each facility must install the required controls, whereas under RECLAIM, the highest cost option is where each facility installs BARCT controls, because the total actual costs may be lower if a facility identifies any other more cost-effective alternative to remain in compliance. Looking at the RECLAIM program as a whole, the major source of cost-savings potential is precisely the differential in each facility's ability to cost effectively reduce emissions at different points in time. This cost-savings has been studied and quantified in economic research of cap- and-trade market mechanism since the 1970s, and the range of cost-savings was estimated to be between 15% and 90 % of command-and-control costs (Chan et al. 2012).

H&SC §39616 (c) specifies that: "In adopting rules and regulations to implement a market- based

[32] Some of the 4 tpd of actual reductions came from operational changes at refineries, which chose to run gas turbines instead of higher-emitting at various points in time. However, just less than two-thirds of the 4 tpd actual reductions were due to facility shut-downs and not measures taken to reduce actual emissions by facilities in the program. In 2005, the installation of 51 SCR units at refineries. However, not one has been installed due to the RECLAIM program. (Four SCR units were installed only due to orders for abatement.) While that choice did not violate RECLAIM, it resulted in facilities not achieving the level of emissions they would have achieved had they applied BARCT. As a result, there is a need to ensure that the currently proposed shave is sufficient to induce emissions reductions equivalent to 2015 BARCT levels, accounting for growth to 2023.

incentive program, a district board shall, at the time that the rules and regulations are adopted, make express findings." One of those findings pursuant to H&SC §39616 (c)(1) is that emission reduction benefits and the costs of the program shall be compared with those of "current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment." H&SC §39616 (c) does not refer to "amendments," and therefore, it does not apply to the proposed rule amendments *per se*. Nevertheless, assuming that the finding needed to continue to be made upon amendment of the rules, it makes sense to make that finding with respect to the entirety of the RECLAIM program since its adoption, because the statute repeatedly refers to "the program" in specifying findings that need to be made. Thus, the structure of H&SC §39616 is directed to the program as a whole, which includes the entirety of the program since its adoption. With the exception of the 2000-2001 period when the California energy crisis took place, the historical discrete NOx RTC prices ($5,500 or lower per ton) have consistently been at the lower end of or below the cost- effectiveness range of pollution controls. As a result, many RECLAIM facilities have accrued substantial cost-savings over the years by being able to delay or forego the installation of pollution control equipment that would have been required at different points in time by command-and-control regulations. And even if the H&SC §39616 (c)(1) finding needs to be made for this proposed shave alone, the proposed shave is expected to only reduce the future stream of this cost-savings. Even so, a reduced cost-savings is still a cost- savings compared to command-and-control regulations. Thus, this amendment will clearly not cost more than the projected cost of command and control.

For example, following the 2005 NOx RECLAIM amendments, not one of the 51 SCRs identified in the BARCT analysis for refineries have been installed because of RECLAIM, and 4 SCRs were installed only due to orders for abatement. As a result, refineries have saved approximately $205 million since 2007 by delaying installation of 47 SCRs.[33] The cost-savings would continue to accumulate as long as refineries are able to further delay the installation of SCRs and still remain in compliance under RECLAIM. This continuous stream of cost-saving would only be reduced or even ceased if the currently proposed shave could eventually induce at least some of the 47 SCRs to be installed.

Staff acknowledges that, for a portion of the smaller emitters that have no cost-effective controls identified so far, they may have been affected by past RTC price spikes and could potentially be impacted by future price fluctuations, either due to their RTC holdings or their limited financial capacity to hedge against price volatilities. However, their potential losses would be at the same time economic gains for the RTC sellers; therefore, the resulting net cost, if any, is expected to be zero or negligible to the entire RECLAIM program, particularly compared with the program's cost savings. While individual facilities may experience different costs and savings, H&SC §39616 applies to the RECLAIM universe as a whole.

[33] The total capital and installation cost for 47 SCRs was estimated to be $460 million in 2005 dollars in the 2005 amendments to the RECLAIM program (not counting the operating and maintenance costs). If the facilities invested this money at a 5 percent nominal rate of return over the 8 years, they would have saved a total of $220 million (i.e., $460 million*(1.05)^8 - $460 million, in 2015 dollars), by the end of 2015. Meanwhile, the affected facilities purchased 1.7 tpd of RTCs in lieu of installing 47 SCRs. The cost of purchasing these RTCs over the past 8 years is estimated to be about $15 million (i.e., 1.7 tpd * 365 days *
$3,000 per discrete ton of RTCs * 8 years). The total net cumulative benefits of the program for refineries only would have been about $205 million. (Based on further analysis using internal RECLAIM compliance data, the total cost of RTC purchases by refineries from 2005-2013 was estimated to be between $16 and $18 million.)

In the 2005 RECLAIM amendments, some stakeholders commented that the shaved RTCs would result in real, significant financial cost to companies and should be recognized as a cost. However, staff disagreed at the time RECLAIM was first adopted and still disagrees today that the cost of shaved RTCs should be recognized as a programmatic cost. Staff has never considered the "cost" of the shaved RTC's to be recognized as a "cost" for determining equivalency with command and control. At the outset of RECLAIM, RTCs were allocated to RECLAIM facilities free of charge, yet they now have value to the facilities as a commodity that can be bought and sold. While RTCs have value, they are not a property right. The proposed amendments to RECLAIM will reduce the number of RTCs. Since there was no cost associated with allocated RTCs for a facility, there should be no financial loss to the RECLAIM universe as the SCAQMD retires them. Any additional purchase of RTCs executed by a facility is made in lieu of emission control. The choice between the RTC purchase and emission control is solely a business decision that is made to generate an expected stream of cost-savings afforded only by the RECLAIM program and not available under command-and-control. Therefore, any RTC investment loss should not be considered as a compliance cost to be compared to the compliance cost under command-and-control regulations. Moreover, this loss may be offset by any potential increase in RTC price due to a decreased RTC supply, which would subsequently raise the market value of a facility's remaining RTC holdings. Finally, any loss of "value" of shaved RTCs cannot be compared to command and control, because in that case there are no RTCs and thus no similar "value" was ever created.

To sum up, many factors are in play that may lower the compliance cost of RECLAIM as compared to CAC. They include:

- RECLAIM facilities have many more options for compliance than facilities under traditional command and control rules, including adding control equipment, process changes, and purchasing RTCs.
- Sources subject to Rule 2005—New Source Review for RECLAIM—are not subject to the 1.2 offset factor that is applied to new and modified sources for non- RECLAIM facilities when using emission reduction credits (ERCs).[34]
- Rule 2005 facilities can sell excess RTC offset holdings at the end of each compliance year resulting from installing or modifying existing control equipment. This option is not available under CAC.
- RTCs resulting from shutdowns have not been subject to the best available control technology (BACT) discount that is applicable to non-RECLAIM sources.
- RECLAIM facilities can take advantage of facility or program emission averaging to implement the least cost controls. Cross-cycle trading under RECLAIM provides additional compliance flexibility.
- The non-RECLAIM facilities are subject to source specific standards (e.g. concentration limits or mass emission limits) that cannot be exceeded at any time whereas, for the most part, RECLAIM facilities can operate their equipment with flexibility and reconcile the emissions with the facility caps at the end of the compliance quarter and year.
- RECLAIM facilities have received monetary benefits from trading their RTCs through the past 22-year life of the RECLAIM program to reduce the costs of compliance.

[34] Rule 2005—New Source Review for RECLAIM.

Based on the aforementioned reasons, the compliance costs under RECLAIM are equivalent to or less than what would have occurred under CAC.

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13. APPENDIX A: 10-YEAR INDUSTRY EMPLOYMENT PROJECTIONS

2012-2022 Industry Employment Projections Los Angeles-Long Beach-Glendale Metropolitan Division (Los Angeles County)			Employment Development Department Labor Market Information Division Published: December 2014
NAICS Code*	**Industry Title**	**Percent Change 2012-2022**	**Annual Average Percent Change**
	Total Employment	**12.8%**	**1.3%**
1133,21	**Mining and Logging**	**9.3%**	**0.9%**
23	**Construction**	**30.2%**	**3.0%**
31-33	**Manufacturing**	**-14.2%**	**-1.4%**
	Durable Goods Manufacturing	**-14.6%**	**-1.5%**
	Nondurable Goods Manufacturing	**-13.6%**	**-1.4%**
22,42-49	**Trade, Transportation, and Utilities**	**12.7%**	**1.3%**
42	**Wholesale Trade**	**12.3%**	**1.2%**
44-45	**Retail Trade**	**13.7%**	**1.4%**
22,48-49	**Transportation, Warehousing, and Utilities**	**10.4%**	**1.0%**
48-49	**Transportation and Warehousing**	**10.7%**	**1.1%**
52-53	**Financial Activities**	**7.4%**	**0.7%**
	Government	**3.7%**	**0.4%**

2012-2022 Industry Employment Projections Anaheim-Santa Ana-Irvine Metropolitan Division (Orange County)		Employment Development Department Labor Market Information Division Published: December 2014	
NAICS Code*	**Industry Title**	**Percent Change 2012-2022**	**Annual Average Percent Change**
	Total Employment	**17.4%**	**1.7%**
1133,21	**Mining and Logging**	**-20.0%**	**-2.0%**
23	**Construction**	**34.0%**	**3.4%**
31-33	**Manufacturing**	**-4.6%**	**-0.5%**
	Durable Goods Manufacturing	**-6.7%**	**-0.7%**
	Nondurable Goods Manufacturing	**0.7%**	**0.1%**
22,42-49	**Trade, Transportation, and Utilities**	**18.4%**	**1.8%**
42	**Wholesale Trade**	**24.8%**	**2.5%**
44-45	**Retail Trade**	**17.0%**	**1.7%**
22,48-49	**Transportation, Warehousing, and Utilities**	**7.5%**	**0.8%**
48-49	**Transportation and Warehousing**	**4.6%**	**0.5%**
52-53	**Financial Activities**	**22.4%**	**2.2%**
	Government	**3.8%**	**0.4%**

2012-2022 Industry Employment Projections Riverside-San Bernardino-Ontario Metropolitan Statistical Area (Riverside and San Bernardino Counties)			Employment Development Department Labor Market Information Division Published: December 2014
NAICS Code*	**Industry Title**	**Percent Change 2012-2022**	**Annual Average Percent Change**
	Total Employment	**19.4%**	**1.9%**
1133,21	**Mining and Logging**	**33.3%**	**3.3%**
23	**Construction**	**58.0%**	**5.8%**
31-33	**Manufacturing**	**-3.3%**	**-0.3%**
	Durable Goods Manufacturing	**-2.5%**	**-0.2%**
	Nondurable Goods Manufacturing	**-5.0%**	**-0.5%**
22,42-49	**Trade, Transportation, and Utilities**	**20.7%**	**2.1%**
42	**Wholesale Trade**	**29.6%**	**3.0%**
44-45	**Retail Trade**	**18.5%**	**1.9%**
22,48-49	**Transportation, Warehousing, and Utilities**	**19.4%**	**1.9%**
48-49	**Transportation and Warehousing**	**20.4%**	**2.0%**
52-53	**Financial Activities**	**15.0%**	**1.5%**
	Government	**5.0%**	**0.5%**

14. APPENDIX B: WEEKLY EARNINGS BY OCCUPATIONAL WAGE GROUP BY MEDIAN WEEKLY EARNINGS

Table A

Quintile	Occupational Title	Median Weekly Earnings
1	Media and communication equipment workers	$398
1	Nursing, psychiatric, and home health aides	$457
1	Occupational therapy and physical therapist assistants and aides	$457
1	Other healthcare support occupations	$460
1	Cooks and food preparation workers	$398
1	Food and beverage serving workers	$424
1	Other food preparation and serving related workers	$385
1	Building cleaning and pest control workers	$467
1	Grounds maintenance workers	$445
1	Entertainment attendants and related workers	$361
1	Personal appearance workers	$480
1	Other personal care and service workers	$431
1	Supervisors of farming, fishing, and forestry workers	$448
1	Agricultural workers	$418
1	Fishing and hunting workers	$448
1	Forest, conservation, and logging workers	$448
1	Other construction and related workers	$461
1	Textile, apparel, and furnishings workers	$250
1	Other transportation workers	$236
2	Life, physical, and social science technicians	$571
2	Other education, training, and library occupations	$582
2	Other protective service workers	$534
2	Supervisors of food preparation and serving workers	$529
2	Animal care and service workers	$524
2	Funeral service workers	$481
2	Baggage porters, bellhops, and concierges; Tour and travel guides	$481
2	Retail sales workers	$516
2	Information and record clerks	$603
2	Other office and administrative support workers	$611
2	Helpers, construction trades	$566
2	Extraction workers	$596
2	Assemblers and fabricators	$525
2	Food processing workers	$509
2	Printing workers	$583
2	Plant and system operators	$573
2	Other production occupations	$555

Table A (Continued)

Quintile	Occupational Title	Median Weekly Earnings
2	Rail transportation workers	$619
2	Material moving workers	$486
3	Social scientists and related workers	$640
3	Religious workers	$767
3	Librarians, curators, and archivists	$685
3	Entertainers and performers, sports and related workers	$763
3	Supervisors of building and grounds cleaning, maintenance workers	$684
3	Supervisors of personal care and service workers	$687
3	Other sales and related workers	$659
3	Communications equipment operators	$638
3	Financial clerks	$624
3	Material recording, scheduling, dispatching, and distributing workers	$623
3	Secretaries and administrative assistants	$681
3	Construction trades workers	$680
3	Electrical and electronic equipment mechanics, installers, and repairers	$706
3	Vehicle and mobile equipment mechanics, installers, and repairers	$737
3	Other installation, maintenance, and repair occupations	$761
3	Metal workers and plastic workers	$645
3	Woodworkers	$623
3	Motor vehicle operators	$689
3	Water transportation workers	$620
4	Drafters, engineering technicians, and mapping technicians	$909
4	Life scientists	$960
4	Counselors and Social workers	$864
4	Miscellaneous community and social service specialists	$773
4	Legal support workers	$856
4	Preschool, primary, secondary, and special education school teachers	$935
4	Other teachers and instructors	$905
4	Art and design workers	$969
4	Health technologists and technicians	$768
4	Supervisors of protective service workers	$897
4	Fire fighting and prevention workers	$939
4	Law enforcement workers	$899
4	Supervisors of sales workers	$776
4	Sales representatives, services	$906
4	Supervisors of office and administrative support workers	$772
4	Supervisors of installation, maintenance, and repair workers	$980

Table A (Continued)

Quintile	Occupational Title	Median Weekly Earnings
4	79 Supervisors of production workers	$902
4	88 Supervisors of transportation and material moving workers	$882
4	Military	$904
5	Top executives	$1,729
5	Advertising, marketing, promotions	$1,384
5	Operations specialties managers	$1,320
5	Other management occupations	$1,141
5	Business operations specialists	$1,074
5	Financial specialists	$1,108
5	Computer occupations	$1,367
5	Mathematical science occupations	$1,244
5	Architects, surveyors, and cartographers	$1,016
5	Engineers	$1,384
5	Physical scientists	$1,261
5	Lawyers, judges, and related workers	$1,738
5	Postsecondary teachers	$1,172
5	Media and communication workers	$995
5	Health diagnosing and treating practitioners	$1,267
5	Other healthcare practitioners and technical occupations	$1,065
5	Sales representatives, wholesale and manufacturing	$1,042
5	Supervisors of construction and extraction workers	$990
5	Air transportation workers	$1,131

15. APPENDIX C: RESPONSE TO STAKEHOLDER COMMENTS

Comments Received at the January 8, 2015, CEQA and Socioeconomic Scoping
A combined CEQA and Socioeconomic Scoping was held on January 8, 2015. There were two specific comments regarding the yet to be completed draft socioeconomic analysis which are addressed below.

Comment #1:
Industry would like to request that the impact of an alternative incremental BARCT shave be analyzed in the socioeconomic assessment.

Response:
The draft socioeconomic document analyzed the impact of this proposed alternative in the Draft Socioeconomic Report released on September 9, 2015. This alternative is listed as CEQA alternative #3—Industry Proposal.

Comment #2:
There are at least a dozen facilities with boilers above 40 mmBtu/hr that will not have cost-effective control equipment to install. The cost-effectiveness of this control equipment is $200,000 per ton and higher, and, as a result, these facilities are only left with the option to buy credits at higher prices after the shave.

Response:
The proposed amendments used a cost effectiveness of $50,000 per ton to determine the quantity of equipment estimated to be cost effective and the amount of emission reductions for the program.

If this comment refers to the refinery sector, the incremental cost effectiveness is $28,000 for refinery boilers/heaters above 40 mmBtu/hr (see Table 4.3 of the staff report). Any controls with cost effectiveness above $50,000 were not considered in the BARCT analysis. If this comment refers to the non-refinery sector, the BARCT analysis indeed did not identify any cost-effective controls for boilers/heaters above 40 mmBtu/hr (see Table 4.2 of the staff report); however, there are cost-effective controls identified for other emission sources.

Under the proposed amendments, the proposed BARCT-based shave would be distributed in the fashion that facilities with identified BARCT would see their RTC holdings reduced by the highest percentages. A non-refinery facility with identified BARCT is expected to be able to reduce facility-wide emissions by installing cost- effective controls on emission sources other than boilers/heaters above 40 mmBtu/hr; however, this same facility would also have the flexibility to reconcile their facility-wide emissions by obtaining sufficient NOx RTCs.

The Draft Socioeconomic Report has analyzed the potential incremental costs of purchasing RTCs at higher prices for 45 facilities where no control equipment has been identified for installation, as well as for the 210 facilities exempt from the shave.

Western States Petroleum Association (WSPA) Comment Letter #1 Received January 30, 2015

Socioeconomic Comment Letter #1

WSPA

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Patty Senecal
Manager, Southern California Region and Infrastructure Issues

VIA ELECTRONIC MAIL

January 30, 2015

Dr. Elaine Chang
Deputy Executive Officer, Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: WESTERN STATES PETROLEUM ASSOCIATION (WSPA) COMMENTS ON THE SOCIOECONOMIC ASSESSMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

Dear Dr. Chang:

The Western States Petroleum Association ("WSPA") is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the Regional Clean Air Incentives Market ("RECLAIM") program. 1-1

WSPA supports the scoping comments submitted by the Industry RECLAIM Coalition for the Socioeconomic Assessment for Proposed Amended Regulation XX.[1] WSPA formally offers the following additional comments:

1. *A ten-year useful equipment life would be more appropriate due to the frequency of District rulemakings. AQMD's 25-year useful equipment life assumption is not appropriate and results in an understated BARCT cost effectiveness analysis. Potential stranded asset costs should be considered in the socioeconomic assessment.* 1-2

[1] SCAQMD, Notice of Preparation (NOP) and Initial Study for a Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014 ("NOP/IS").

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For some time, South Coast Air Quality Management District ("AQMD" or "District") has been using a 25-year equipment life assumption to compute emission control cost effectiveness when conducting new Best Available Control Retrofit Control Technology ("BARCT") analyses. This equipment life assumption results in a systemic understatement of emission control costs because BARCT is typically redefined on much shorter terms. To that point, the District established BARCT for all of the source categories being considered under this Regulation XX rulemaking only ten years ago (i.e., 2005). Calculation of control costs of the 25-year term distorts the true cost associated with these rules. 1-2 Concluded

As recommended in ABT Associates' recent evaluation of the District's socioeconomic assessment process,[2] AQMD should ensure that the control costs used in the Regulation XX socioeconomic assessment include the full cost of retrofitting existing controls or installing new controls. This would include consideration of any stranded asset costs, such as when the proposed BARCT determination requires replacement of prior investments for emission control equipment or effectively mandates the replacement of basic equipment (e.g., gas turbines).

2. *The District's capital cost estimates are significantly lower than refiners' estimates; the socioeconomic assessment should consider a scenario based on these higher costs.*

As with past rulemakings, the District's emission control costs for refineries have been underestimated. Norton Engineering Consultants ("Norton") recently concluded a review of the District's BARCT analysis[3] and concluded that emission control costs for most refinery source categories would be significantly higher than those estimated by District staff. For example:

- FCCUs: Norton's Present Worth Value (PWV) estimates for FCCUs were >60% higher than the last PWV estimates presented by AQMD staff to the NOx RECLAIM Working Group (note: range of variance was between -19% and +138% depending on the unit) 1-3
- Refinery Heaters/Boilers: On average, Norton's PWV estimates were >90% higher than the last estimates presented by AQMD staff (note: range of variance was a function of size).[4]
- Coke Calciner: Norton concluded the PWV costs will be >75% higher than the most recent AQMD Staff estimates, and that for BARCT performance in the range of 5-10 ppmv NOx (i.e., not 2 ppmv).[5]
- Sulfur Recovery Units/Tail Gas Treatment Units: Norton concluded that PWV costs will be higher than the AQMD Staff with range of variances between +37% and +267% depending on the unit.[6]

[2] ABT Associates, Review of the SCAQMD Socioeconomic Assessments, Documentation, Task 1-4 Final, 14 August 2014.
[3] Norton Engineering Consultants, Inc., SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[4] Comparison of data presented in Norton Report and AQMD Staff data, presented to the NOx RECLAIM Working Group Meeting (WGM), 7 January 2015 (slide 25).
[5] Comparison of data presented in Norton Report (p. 21) to AQMD Staff data presented to the NOx RECLAIM WGM, 31 July 2014.
[6] Comparison of data presented in Norton Report (p. 34) to AQMD Staff data presented to the NOx RECLAIM WGM, 31 July 2014.

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Based on a confidential and blinded cost survey of WSPA members conducted last year, it appears that the Norton cost estimates may also significantly understate the refinery sector's overall cost of control for this Regulation XX rulemaking. Because RECLAIM is a market-based emission control program, the individual companies have the flexibility to develop their own strategies for complying with their facility-wide emission limits. These strategies can involve emissions control projects or RTC trading and the companies are incentivized under the program to seek the most cost-effective approach for their particular situation. 1-3 Concluded

WSPA, through a third party contractor, conducted a confidential cost survey of the Southern California refineries concerning total capital and operating costs for their compliance strategies for the District's proposed NOx RECLAIM shave.[7] This information is highly proprietary and refiners submitted this information on a confidential basis to the third-party contractor who de-identified and aggregated the compliance costs for the overall industry. The current refining industry forecast suggests the compliance costs of this rulemaking may be nearly twice the most recent cost estimate presented by AQMD staff.[8]

Given the magnitude of this cost variance, WSPA is willing to make its contractor, Stillwater Associates, available to District socioeconomic staff to discuss the aggregated findings of WSPA's confidential survey for the refining industry. In addition, our members, as individual refiners, are willing to discuss with the District staff, individual inputs to the confidential survey to substantiate the methodology and its findings. We respectfully request that the District's socioeconomic assessment consider this higher cost scenario as it would better inform the Governing Board and stakeholders of the true, potential socioeconomic impacts associated with the proposed rulemaking. 1-4

We appreciate your consideration of these comments in the scoping of the socioeconomic assessment for the Regulation XX rulemaking, and will continue working with AQMD staff towards the development of sensible proposal for the RECLAIM program.

Very truly yours,

Patty Senecal

Responses to WSPA – Socioeconomic Letter #1

1-1. Thank you for the comments provided.

1-2. Although the Bay Area AQMD and EPA OAQPS assume an SCR lifespan of 20 years, staff used a 25-year equipment life for SCRs to be installed based on the profiles of SCRs used by refineries in the Basin. Nearly 30 percent of the refinery combustion equipment in the Basin has SCRs that were installed more than 25 years ago, and more than 60 percent of the refinery combustion equipment has SCRs that were installed more than 20 years ago. These units are still in operation and thus support the assumption of a 25-year useful life in the cost analysis.

In addition, there is no demonstration that assets have been stranded as a result of advancements in BARCT, since such advancements may be based on improvements in the earlier air pollution control technology. Thus, to artificially reduce equipment life based on the potential for new BARCT requirements in the future is speculative, and will be addressed at the time of any rulemaking.

1-3. The cost estimates used in the staff report are what is used in the socioeconomic analysis. Please see the Staff Report for more information regarding the difference between staff estimates and NEC estimates.

1-4. As indicated in Response 1-3, please refer to the Staff Report for cost estimates and related assumptions. In a comment letter dated August 21, 2015, Western States Petroleum Association (WSPA) stated, "WSPA believes that the District's cost effectiveness calculations significantly understate the costs associated with achieving the proposed BARCT levels. We believe that even the Norton analysis underestimates actual costs. WSPA is currently developing additional information based on detailed engineering assessments that more accurately represent the costs associated with the proposed BARCT. We will submit this information to the record as it becomes available." WSPA also stated in a working group meeting that their cost estimates were 2 to 3 times higher than those estimated in the Staff Report. Staff has met with three refineries who provided varying levels of detail regarding their projected costs that would occur for these facilities to comply with the proposed amendments. There is not sufficient information for staff to verify the WSPA cost estimates. Some of the difference related to staff using an incremental cost-effectiveness calculation, which assumes that 2005 BARCT levels are in place, which may or may not be the case for individual facilities, but is needed for a programmatic evaluation. The individual facilities include total costs, and often include full costs for additional equipment such as substations that may support the new control equipment, as well as other operations at the facility.

Comment Letter #2 Received January 30, 2015
California Council for Environmental and Economic Balance (CCEEB), Southern California Air Quality Alliance (SCAQA), Regulatory Flexibility Group (RFG), and WSPA

Socioeconomic Comment Letter #2

California Council for Environmental and Economic Balance | Southern California Air Quality Alliance | Regulatory Flexibility Group | WSPA Western States Petroleum Association

30 January 2015

Dr. Elaine Chang
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SUBJECT: INDUSTRY COMMENTS ON THE SOCIOECONOMIC ANALYSIS FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

Dear Dr. Chang:

These comments are presented on behalf of the members of leading Southern California businesses represented by the California Council for Environmental and Economic Balance ("CCEEB"), the Regulatory Flexibility Group ("RegFlex"), the Southern California Air Qaulity Alliance ("SCAQA"), and Western States Petroleum Association ("WSPA"). The members of these business groups are major Southern California employers who own and operate facilities that comprise most of the Regional CLean Air Incentives Market ("RECLAIM") program. 2-1

This "Industry RECLAIM Coalition" formally offers the following scoping comments on Socioeconomic Analysis for Proposed Amended Regulation XX.[1]

1. *The socioeconomic analysis should incorporate the procedural improvements recommended under the ABT study;[1] these are important enhancements to the District's socioeconomic analysis process.* 2-2

The District recently commissioned ABT Associates to conduct an evaluation of the SCAQMD's socioeconomic assessment process.[2] ABT made a number of recommendations relevant to this rulemaking which SCAQMD committed to implement.[3] This included but was not limited to the following:

[1] SCAQMD, Notice of Preparation (NOP) and Initial Study for a Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014 ("NOP/IS").
[2] ABT Associates, Review of the SCAQMD Socioeconomic Assessments, Documentation, Task 1-4 Final, 14 August 2014.
[3] AQMD, Summary of ABT Recommendations & SCAQMD Staff Response, presented to Governing Board, 7 November 2014.

Dr. Elaine Chang, SCAQMD
30 January 2015

- Appropriately consider useful life of pollution control equipment; need to consider stranded costs where early replacement is required
- Present both DCF and LCF methods" with appropriate thresholds
- Ensure control costs of new regulations include complete estimate of retrofitting existing controls. Clearly cite and include all sources of control cost estimates.
- Improve transparency through external peer reviews

2-2 Concluded

While these recommendations were agreed to by AQMD Staff in the context of the 2016 Air Quality Management Plan ("AQMP"),[4] the Industry RECLAIM Coalition believes they are more broadly important than just for the AQMP. The proposed revisions to Regulation XX represent a significant rulemaking which could have significant socioeconomic impacts to the Southern California regional economy. We recommend that these process improvements recommended by ABT Associates should be fully incorporated into the socioeconomic analysis for the Regulation XX rulemaking.

2. *The socioeconomic analysis should fully consider the comparative economic impacts of project Alternatives presented in the Draft Program Environmental Assessment ("PEA") for Proposed Amended Regulation XX, including the Industry Coalition's alternative proposal.*

Under the 2012 AQMP, the Governing Board approved control measure CMB-01 which authorized further reductions from the NOx RECLAIM program. The control measure authorized by the Governing Board was based on a range of 3-5 tons per day ("TPD") of RECLAIM Trading Credits ("RTCs") being removed from the program. While stakeholders understood the eventual rulemaking could differ, the current Staff proposal as presented in the NOP/IS would be substantially larger at nearly 13 TPD.

2-3

This Industry RECLAIM Coalition has presented an alternative methodology for demonstrating command-and-control equivalency which would reduce the program's quantity of RTCs by an amount limited to only those reductions that can be directly attributed to the advancement of Best Available Retrofit Control Technology ("BARCT"). While the industry proposal could also result in RTC reductions greater than the approved AQMP control measure, it would be less than what has been presented by the AQMD Staff.

Given the significant differences between the Proposed Project and project Alternatives, we recommend that the socioeconomic analysis quantify the potential economic impacts of each policy option (i.e., the Proposed Project and all project Alternatives) for the Governing Board and stakeholders.

3. *The socioeconomic analysis should consider total costs associated with the Proposed Project and project Alternatives.* 2-4

Dr. Elaine Chang, SCAQMD
30 January 2015

While the BARCT technical analysis being conducted by AQMD Staff is being based on incremental cost effectiveness,[5] the actual economic impacts associated with this rulemaking will be based the total costs for compliance. To understand the potential economic impacts of this rulemaking, the socioeconomic analysis should consider the total capital cost and total increased operating costs as compared to the current baseline condition.

Furthermore, the socioeconomic analysis should consider the cost to RECLAIM program participants for RTC reductions which cannot be directly attributed to the advancement of technology (i.e., BARCT). The AQMD Staff proposal would appear to cause RTC reductions beyond those directly attributable to new BARCT.[6] RECLAIM program members will bear the costs for new capital and operating expenses associated with new BARCT, and they will also be collectively impacted by potential RTC reductions which are not tied to BARCT. These impacts may be regionally significant. 2-5

The socioeconomic analysis should fully quantify all these costs in assessing the potential economic impacts for the Proposed Project and each project Alternative to ensure the Governing Board and stakeholders are informed of the socioeconomic impacts associated with the different policy options.

The RECLAIM program remains vitally important to the health of Southern California's economy and environment. The members of this coalition have actively participated in this rulemaking through the NOx RECLAIM Working Group over these last two years, and we look forward to continuing to work with you and the District's Staff on the significant rulemaking.

Very truly yours,

Bill Quinn
California Council for Environmental and Economic Balance

Michael Carroll
Regulatory Flexibility Group

Curtis Coleman
Southern California Air Quality Alliance

Patty Senecal
Western States Petroleum Association

[5] For this rulemaking, incremental cost effectiveness is based on the cost and emissions benefit differences that would theoretically be observed between the new 2015 BARCT technology and emissions performance level as compared to the prior 2000/2005 BARCT technology and emissions performance level.
[6] AQMD NOx RECLAIM Working Group Meetings, 7 January 2015 and 31 July 2014.

Responses to CCEEB, RegFlex, SCAQA, and WSPA – Socioeconomic Letter #2

2-1. Thank you for the comments provided.

2-2. The Socioeconomic analysis of the proposed amendments to the NOx RECLAIM has implemented, to the extent possible, methodological and procedural improvements based on the recommendations put forward by Abt Associates in their 2014 report. These improvements include:

- Conducting Socioeconomic Scoping Session with CEQA Scoping on January 8, 2015
- Providing a more-than-45-day review period for the Draft Socioeconomic Report (Draft released on September 9, 2015)
- Identifying key socioeconomic issues and assumptions
- Analyzing the impacts of potential alternatives, including the Industry Proposal
- Providing a range of costs and job impacts to reflect different assumptions
- Clearly citing and including all sources of control cost estimates
- Conducting sensitivity analysis by analyzing a scenario in which no control installation spending occurs in the Basin
- Providing better documentation of assumptions and methodologies

Finally, although not included in the socioeconomic analysis, the staff report presents cost-effectiveness analysis results both LCF and DCF methodologies.

2-3. The Draft Socioeconomic Report has analyzed the potential economic impacts of four policy alternatives (and no impacts under the “No Project” alternative), including an Industry Proposal, which is represented as CEQA alternative #3.

2-4. The draft socioeconomic impact assessment estimated total compliance costs associated with the proposed rule amendments and CEQA alternatives. In addition to the potential compliance cost of control equipment installation and operation for these 20 facilities, the proposed amendments may potentially result in incremental costs for some of the 45 facilities where no BARCT was identified, and some of the 210 facilities that are not shaved but would need to continue purchase RTCs which may increase in price. These incremental costs would be the result of both additional RTCs that would be purchased from the market and due to potential RTC price increases after the shave. However, the total cost to RTC buyers is at the same time an economic gain for RTC buyers; therefore, the net compliance cost related to RTC transactions would cancel out.

2-5. As discussed in Response 2-4, the draft socioeconomic economic report considers the total compliance costs associated with the proposed NOx RECLAIM amendments and also with each CEQA alternatives. This is done by comparing the proposed amendments against a baseline of “business as usual”.

Based on staff's analysis, a shave of 14 tpd from current RTC levels of 26.51 tpd is necessary to attain the 12.51 tpd (26.51 tpd – 14 tpd = 12.51 tpd) of remaining NOx emissions in 2023. This level includes installation of 2015 BARCT, an allowance for growth, a compliance margin, and adjustments to account for uncertainties in the BARCT analysis. The cost of full BARCT installation represents the most conservative (i.e., maximum) cost estimate because, under RECLAIM, the total actual costs may be lower if a facility identifies any other more cost-effective alternative to remain in compliance.

The draft socioeconomic report also included discussion of the value of shaved RTCs (Please see Section 9—Market Analysis for more details). At the outset of RECLAIM, RTCs were allocated to RECLAIM facilities free of charge, yet they now have value to the facilities as a commodity that can be bought and sold. While RTCs have value, they are not a property right. The proposed amendments to RECLAIM will reduce the number of RTCs. Since there was no cost associated with allocated RTCs for a facility, there should be no financial loss to the RECLAIM universe as the SCAQMD retires them. Any additional purchase of RTCs executed by a facility is made in lieu of emission control. The choice between the RTC purchase and emission control is solely a business decision that was made to generate an expected stream of cost-savings afforded only by the RECLAIM program and not available under command-and-control. Therefore, any RTC investment loss should not be considered as a compliance cost to be compared to the compliance cost under command-and- control regulations. Moreover, this loss may be offset by any potential increase in RTC price due to a decreased RTC supply, which would subsequently raise the market value of a facility's remaining RTC holdings. Finally, any loss of "value" of shaved RTCs cannot be compared to command and control, because in that case there are no RTCs and thus no similar "value" was ever created.

Socioeconomic Letter #3 Kavet, Rockler & Associates LLC (on behalf of WSPA)

Kavet, Rockler & Associates, LLC
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October 16, 2015

Dr. Shah Dabirian
Program Supervisor, NO_x Reclaim
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

ELECTRONIC SUBMISSION

RE: Revised Draft Socioeconomic Report for Proposed Amendments to Regulation XX-Regional Clean Air Incentive Market (RECLAIM) NO_x RECLAIM

Dear Dr. Dabirian:

At the request of the Western States Petroleum Association (WSPA), we were asked to review the October, 2015 draft "Socioeconomic Report for Proposed Amendments to Regulation XX-Regional Clean Air Incentive Market (RECLAIM) NO_x RECLAIM" prepared by the South Coast Air Quality Management District (SCAQMD.) Specifically, we were asked to review the draft analysis as regards methodology, implementation of the economic model supplied by Regional Economic Models, Inc. (REMI), and to offer relevant comments that have a bearing on the adequacy or accuracy of the economic analysis given in the draft report. We note that we posed a number of questions during a teleconference on October 7, 2015 that included a number of the SCAQMD staff, as well as WSPA representatives. Some of what we learned during that discussion has carried through to comments we make here and there are a number of questions that remain unresolved. Below, we offer our questions and comments under each of the three categories.

I. METHODOLOGY

a. Omission of RTC Costs in Macroeconomic Impact Estimates

In the revised draft report, it is noted that the proposed best available retrofit control technology (BARCT) shave will produce annualized capital and operating cost changes of $72 million per year at a 4% discount rate (see ES-3 and later). These estimated BARCT costs are then used in estimating the macroeconomic impact on the regional economy. However, it appears as though compliance costs involving RTC allowances were excluded from the macroeconomic impact analysis. We note that firms with inadequate allowances after the shave will face higher production costs when securing *additional* RTCs. The argument that SCAQMD offers, if we understand it correctly, is that the RTC allowances were made available freely at the start of the program and that any subsequent trading of allowances merely represents a shift in asset values between seller and buyer with no economic gain or loss to the region. We agree with this view so long as the sole function of the RTC is limited to a bookkeeping store of value. However, RTC's are not merely abstract assets: Very much like certain metal commodities such as gold and silver, RTCs are at once both assets with a market-determined value and a critical production input in the manufacture of certain goods. When a firm decides to offset an excess of emissions at a particular level of output, there must be seller of RTCs that has surplus allowances at its own level of emissions to sell. Note that carrying surplus RTC allowances does not change the seller's production costs, but does represent an opportunity cost that affects its current net income if the market value of its RTCs is greater than zero. On the other hand, the buyer must pay the current market cost for each additional RTC that it requires, and this cost is *incremental* to all other costs in their production function. These costs will be incurred by any facilities when their RTC holding levels fall below their emissions levels, which can occur for a number of reasons, including mandated allowance reductions. This production cost increase is by design, intended to create an incentive to reduce emissions by investment in improved control or combustion technology or by reducing production volumes if this reduces emissions. Were it the case that the shave had no effect on operating costs, no incentive would exist to alter emitters' production technologies or output. I-A

We note that you have already estimated the total RTC allowance cost changes for 255 facilities (see ES-5 "Market Analysis, para. 2) as ranging from $14 to $365 million. We do not see why the addition of the RTC costs to the production cost policy variable in the REMI model cannot be included to complete the total program cost macroeconomic impact. On p.40, you note that because actual RTC price changes cannot be accurately predicted, you cannot include market effects in the REMI macroeconomic simulation. We contend that a reasonable range of value could be applied to develop a range of total macroeconomic impact. I-A

By ignoring the RTC price changes on production costs, this analysis implicitly sets the RTC price change to be zero, a value that seems unreasonable.

b. **Growth Assumptions**

For determining which firms will need to acquire additional RTC allowances in the future, it is stated on p. 42, paragraph 2 that you have applied an industry specific annual growth rate to the 2011 actual emissions to project when and by how much a facility will exceed its RTC holdings. These growth rate assumptions are fundamental to estimating the RTC market impact component. It was noted during the teleconference that three different growth rate assumptions were used and that these are shown in the footnotes found on p. 45 and 47 of the revised draft report. Also during the phone conference, it was noted that the industry projections used are mandated in State legislation. Could we please have a complete citation for the industry-level projections that were used? (We note that although the REMI model is not a forecasting model per se, its baseline economic projection is derived from known and credible macroeconomic forecasts and the implicit growth rates for each of the industries in the model could certainly function develop a medium-run economic outlook for SCAQMD's purposes.) We contend that a three-sector scheme for estimating future RTC allowance requirements is far too aggregate and may misrepresent the severity of the proposed regulatory change on industries that are important to the regional economy. I-B

c. **Industry-Level Data**

When projecting future demand for RTC allowances, we suggest that it would be very useful for SCAQMD to aggregate facilities to a NAICS 6-digit industry-level or REMI 70 sector level for an appropriate time interval and produce data files of output, emissions, employment, and RTC holdings. Such information would allow the SCAQMD and public to directly identify which industries are more or less affected by the non-BARCT market effects and which are greater or lesser contributors to overall regional economic activity and emissions. This information is entirely missing in the analysis despite the need for such information being listed as a report requirement on pp. 5-6 of the draft. I-C

II. REMI IMPLEMENTATION QUESTIONS

a. Classification of BARCT Compliance Costs

In Table 17, we see both BARCT compliance costs and compliance spending listed as inputs to the REMI model. We do not see the specific REMI "policy variables" (as they are known in the model) listed or described in even a general context. However, we do see that one-time capital costs are entered into the REMI model as Machinery Manufacturing and installation costs entered as Construction costs. We would also expect that operating costs for the new capital equipment would be entered into the REMI model as changes in the production costs for the affected industry, and that the suppliers of the goods and services required to run the new capital equipment would see a change in appropriate industry sales values in the REMI model. Is this how compliance costs were entered into the model? What were the job and output impacts of the compliance costs? These can be presented separately from RTC allowance job and output impact. For the compliance spending, how were the machinery manufacturing and installation costs entered? II-A

b. BARCT Installation Costs as Construction Industry Spending

During the phone conference, one SCAQMD representative (apologies for not noting who the speaker was at the time) stated that the installation costs associated with the BARCT capital equipment entered into the REMI model as construction sector spending. We contend that this should have been entered using the wage payments policy variable for the construction sector or the employee compensation policy variable for construction sector (i.e., fully-loaded labor costs including wages, fringes, and benefits.) If entered as general construction sector spending, the REMI model will divide-up the spending over a multitude of inputs: Approximately 20 percent of the total amount will be classified as labor costs, 60 percent will assigned to materials and services expenditures (including amounts for lumber, gypsum board, glass and glazing products, lighting products, flooring products, concrete products, etc.) things unlikely to be purchased for installing refinery equipment, and the last 20 percent will be classified as overhead and profits which would have already been included in the equipment purchase. This appears to be incorrect to us. II-B

c. **Production Location of BARCT Capital Equipment**

Also during the phone conference, we established that SCAQMD knows the manufacturer of capital goods and can determine location of manufacture for that equipment. In that case, it is always recommended that we use this knowledge and avoid use of the general regional purchase coefficient that is included in the REMI model. The regional purchase coefficients are, at best, an approximation of a general regional production pattern and if one knows the actual geographic source, there is no point in allowing large errors to reduce the impact estimation quality. The same can be said of the installation labor, if the manufacturer requires that its own labor be used. II-C

d. **BARCT Equipment Purchases as Increment to the Regional Capital Stock**

We determined that SCAQMD did not increment the regional capital stock in the REMI model. This is not automatically done with investment expenditures in the REMI model, despite what one SCAQMD representative said during the phone conference. The user must specifically enter the value of the BARCT capital equipment and installation costs to the regional nonresidential capital stock policy variable. The consequence of omitting this step is having slightly overstated aggregate capital investment. The BARCT investment will offset implicit future investment, resulting in higher future net job-creation impact. II-D

e. **Review of REMI Input File**

To assure ourselves that the REMI model was correctly implemented, we submitted a public records request, at SCAQMD's suggestion, to obtain a copy of the relevant worksheets and REMI input files. We received these data on October 14th and will review to see specifically what direct impact data were entered into the model, and how they were entered in terms of specific policy variable categories. We will submit comments, if needed, at a later date to address any specific concerns. II-E

III. GENERAL QUESTIONS AND/OR COMMENTS

a. At no point in the draft analysis is there a figure that represents the total cost of the proposed regulatory change. It would be very helpful if SCAQMD can develop such a figure (or a value range) that allows the reader to know the potential total. III-A

b. The "Short-Term Economic Outlook" section (starting on p.6) offers no insights into the industries of the regulated facilities. It offers a two year forecast (of which ¾ of a year is now history and not outlook), which is of limited value in the context of 10 year projection period for emissions and economic activity. Since we are not given an economic outlook for markets that can change significantly over the next 10 years, we do not know how South Coast believes events will unfold and have no basis to assess the reasonability of the cost estimates for RTC allowances and effect on specific industries. III-B

c. We attempted to verify the short-run "outlook" figures using the cited sources, i.e., the California State University at Fullerton, Wells Fargo California Economic Outlook, and the Los Angeles Economic Development Corporation. We could not match- up table data from the draft with (several of) the cited sources. We suggest that a full citation of the source used for this section would be helpful. III-C

d. In the "Competitiveness: section, p. 34 it is stated, "The proposed amendments are not expected to impose discernable impacts relative to the cost of services or delivered prices of the affected facilities." Given the incomplete macroeconomic analysis with respect to RTC allowance pricing impacts, we think this conclusion is premature. If you add the allowance price effects into production cost estimates, REMI can solve for price and interregional trade changes that will inform us whether the effects are significant or not. These cannot be dismissed out-of-hand. III-D

e. Regarding ability to bear the costs of required investments, references are made on P. 34 to the refining industries gross revenues of the corporate owners of the facilities. This is an entirely inappropriate metric when conducting a regional economic evaluation as to whether the change in regulation is burdensome. The refineries do not operate in a national or international market reflected by total international corporate revenues. Rather, they operate in a regional market where the burden of the mandated and market changes should be measured against a figure such as regional refinery non-labor value added, which measures the value produced by capital net of depreciation, retained earnings, and earnings distributed to owners (i.e., shareholders), excluding raw material input costs and labor input. The change in non-labor value added will inform us as to whether the regulation change is burdensome. III-E

f. The second paragraph and footnote given on p. 34 offers an estimate for determining the cost-per-gallon of gasoline due to the proposed regulatory changes. Since, once again, these ignore RTC acquisition costs; the figures are likely to be low. Furthermore, it ignores the natural forces of the transportation fuel markets and it assumes that the region faces no outside competition from gasoline imports. This leads to the misleading conclusion that refineries can fully pass on all costs associated with the revised regulations. For example, the calculation ignores known gasoline imports to region via the Port of Los Angeles, which amounted to $2.9 billion in 2012, a relatively small amount compared to the $70 billion of regional refinery output[1], but proof that the market is not closed to competitors and that not all costs can be assumed to be passed on to consumers. III-F

Please let us know if you have questions regarding the specific points we have raised. We look forward to your reply and thank you for your assistance.

Sincerely,

cc: Dr. Phil Fine, SCAQMD
Sue Gornick, WSPA

[1] HIS Regional Economic Service county database, 2014.

I. METHODOLOGIES

Response to Comment I-A:

The commenter noted that, in the Revised Draft Socioeconomic Report released in October 2015, staff already estimated that potential incremental compliance cost for the projected NOx RTC buyers. The incremental cost for an affected facility is estimated as the difference in its current compliance cost and the projected higher compliance cost, which would be the result of either the proposed NOx RTC shave per se or any increase in NOx RTC prices due to a potentially decreased supply of NOx RTCs in the market.

Since any incremental compliance cost paid to obtain NOx RTCs would benefit NOx RTC sellers, the incremental compliance cost on the net for the entire RECLAIM universe would be by far lower than the gross compliance cost incurred by NOx RTC buyers. Any positive net compliance cost would be equivalent to the financial gains accrued to NOx RTC brokers. As the commenter noted, the Revised Draft Socioeconomic Report does state that, "[b]ecause the RTC price scenarios were set arbitrarily at various price points for illustrative purposes only, and any actual price increase cannot be accurately predicted, staff did not include the result of price analysis as an input for the REMI model to assess the macroeconomic impacts that could be potentially generated due to a redistribution of wealth within the RECLAIM universe as a result of RTC transactions." Staff did not assume the RTC price changes on production costs to be zero. In fact, in the Final Socioeconomic Report, job impacts have been estimated using REMI for the incremental compliance costs related to NOx RTC transactions. Please see Section 9.59.5 REMI Job Impacts of RTC Purchases for more details.

Response to Comment I-B:

The growth factors used in projecting the 2023 NOx emissions are the same set of growth factors used in the 2012 Air Quality Management Plan (AQMP), with the base year set in 2011. Nearly all of the growth factors were based on the growth projections made in the 2012 Regional Transportation Plan/Sustainable Community Strategies (RTP/SCS) prepared by the Southern California Association of Governments (SCAG). The only exception is for Electricity Generating Facilities (EGFs). EGF emissions were projected using 2012 as the base year and with updated growth factors based on the 2014 Gas Fuel Report published by the Southern California Gas Company. (See Appendix W of the October 6, 2015 Draft Staff Report for more details).

In order to project the overall 2023 NOx emissions among current NOx RECLAIM facilities, SCAQMD staff began by projecting the 2023 emissions for each facility, based on the aforementioned growth factors that vary by county and by 3-digit North American Industry Classification System (NAICS) code. The projected emissions at the facility level were then aggregated to the group level to arrive at the composite growth factors referenced in the Revised Socioeconomic Report (i.e., those noted by the commenter). Therefore, the projected total NOx emissions for any of the groups analyzed in the Report are consistent with the summation of projected NOx emissions across all facilities in a group.

When it comes to analyzing the potential buyers of NOx RTCs and the additional credits that will be needed in the post-shave market, staff acknowledges that the use of the group-level composite growth factors can potentially generate somewhat different estimates than using the more disaggregate growth factors that vary by county and by 3-digit NAICS. The difference would be larger, with greater within-group variations of projected NOx emissions and RTC holdings; however, the magnitude and even the direction of this difference is a priori unclear. If, as reasonably expected, the projected NOx emissions mostly occur at facilities with higher levels of post-shave RTC holdings, then the projected total additional NOx RTCs that will need to be purchased, and thus the associated incremental compliance cost, will have been overestimated in the Report. In a letter from Kavet, Rockler & Associates dated November 19, 2015, it is stated that "it would be preferable to provide NAICS-3 estimates for industry growth accompanied by estimates for industry emissions and allowance balance at same NAICS-3 level." Staff continues to believe that presenting the potential incremental compliance cost for the two major groups of facilities that are distinguished by whether they would be shaved or not (and both without identified cost-effective controls) is a more appropriate method to illustrate overall impacts. Staff is working to compile this information and will respond to the commenter.

It should also be noted that, to be conservative about compliance cost estimates, staff assumes that all facilities with identified cost-effective controls would install such devices and incur the associated compliance costs. In reality, the installation of all cost-effective controls will not likely come true unless NOx RTC prices would rise to a sufficiently high level to make control installation a more economical compliance option. In fact, the estimated cost-effective values of several categories of cost-effective control equipment lie well above the proposed price trigger of $22,500 per ton (based on a 12-month rolling average of discrete NOx RTC prices), above which all non-usable/non-tradable NOx RTCs would be converted to usable/tradable RTCs to stabilize market prices.

Response to Comment I-C:

As mentioned in the previous response, the growth factors used to project the 2023 NOx emissions vary by county and by 3-digit NAICS. The REMI 70-sector model used by the SCAQMD staff has a similar level of industry aggregation and the same geographical breakdown.

The growth factors used for point sources in the 2012 AQMP are directly based on industry output, employment, or population growth projections made by SCAG. (The only exception is for EGFs, whose growth factors were based on the 2011 Gas Fuel Report. For details, please refer to the 2012 AQMP: Table III-2-5 in Appendix III available at http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/appendix-iii-final-2012.pdf.) Therefore, it appears redundant to additionally report the underlying growth projections used to generate the growth factors. Moreover, the data files, which contain NOx emission and RTC holding projections and were used to generate estimates reported in Section 9: Market Analysis, can be requested via a public records request, similar to the commenter's previous request for REMI data files used in the Revised Draft Socioeconomic Report.

Furthermore, the socioeconomic assessment has met the legal requirements listed on pp. 5-6 of the Revised Draft Socioeconomic Report. Industry distribution was not included explicitly for the 219 facilities, because facilities in this group represent a range of industries, but are largely comprised of manufacturing, mining, oil and gas exploration, and utilities industries. Cost impacts on these facilities individually are expected to be small (if not zero). Any cost impacts that could potentially occur would be the result of any NOx RTC price increases due to the proposed amendments, and they are expected to be proportional to the amount of NOx RTCs currently needing to be purchased by these facilities. This information has now been included in Section 6: Affected Facilities.

II. REMI IMPLEMENTATION QUESTIONS

Response to Comment II-A:

Table 17 lists the industry sectors modeled in REMI that would either incur cost or benefit from the compliance expenditures. A full lists of policy variables are beyond level of detail needed for the average reader and thus are not presented in the report. (Policy variables are the channels through which the estimated economic changes due to the proposed amendments—for example, changes in production costs and market demand for goods or services—are inputted into REMI to generate macroeconomic impacts.) However, they are available to the public, and as requested by the commenter in his Public Records request, staff has prepared and sent REMI RWB files with a complete list of policy variables on October 14, 2015.

The operating and maintenance costs of the new capital equipment were modeled in REMI as a change in production cost for the RECLAIM facilities with identified cost-effective controls. The suppliers of the goods and services of these new equipment would receive additional spending, modeled as an increase in industry specific exogenous final demand. Please note that not all the additional spending would benefit the local economy, as the affected facilities may purchase the control equipment and the related goods and services from outside the region. The distribution of these additional spending within and outside the region is determined internally by the REMI model's Regional Purchase Coefficients. As a sensitivity test to this implicitly assumed spending distribution, staff also conducted a worst-case scenario where no additional spending would occur within the region.

As noted by the commenter, in the Draft Socioeconomic Report, staff did not enter into the REMI model the incremental compliance cost due to either additional RTC purchases or any increases in NOx RTC price. For the specific response to this comment, please see the response to Comment I-A.

Response to Comment II-B:

The installation costs associated with the BARCT capital equipment were entered into the REMI model as an increase in exogenous final demand in the construction sector. The commenter recommended that staff use the wage payments policy variable instead. However, it should be noted that, first, the increased exogenous final demand in the construction sector (the policy variable that staff used) automatically adds labor income based on the underlying Input-Output table and labor productivity. Second, after consultation with REMI staff and conducting several simulations, staff confirmed that the wage payments variable is an inappropriate policy variable to use. The most important reason is that it would inappropriately ignore the direct job creation impact due to construction labor demands by control installation. As a result, an excessively small job impact would be observed in the construction sector, mainly due to indirect effects such as those working through increased labor income that would drive up residential construction labor demand. In fact, the largest impact of increased wage payments in the construction sector would be, literally, a higher average wage per worker in the construction sector. Staff does not consider this as the most appropriate modeled impact in the context of control installation.

Staff acknowledges that, when entered as an exogenous demand in the construction sector, the additional spending associated with control installation would result in increases in intermediate goods and services in the REMI model that, in reality, are remotely related to control installation. However, this result is largely related to the level of industry aggregation in the REMI model and, as advised by REMI staff, may be partially mitigated by choosing an appropriate translator policy variable that will constrain the direct effect to fewer, more disaggregate construction industries that are a subset of the broader construction sector. However, the use of this translator variable mitigates but does not completely resolve this issue. Moreover, the use of wage payments variable, as recommended by the commenter, would not be the solution to this problem.

In a comment letter sent by Kavet, Rockler & Associates on November 19, 2015, the commenter maintained the opinion that control installation cost should be entered into REMI as “Wage Bill-Construction” or “Compensation (amount)-Construction”. Staff does not agree with this opinion as already explained in Response to Comment II-B. A simple exercise of entering the same amount of construction spending using the three different policy variables showed that the two policy variables suggested by the commenter generated an unreasonably low share of construction jobs among total jobs created. For example, in a simple exercise where a same amount of construction spending was increased in the region in one single year, more than 50 percent of total jobs projected to be created that year was concentrated in the construction sector when entered as “Exogenous Final Demand-Construction”. In comparison, only 7-11 percent of jobs created was in the construction sector when entered as “Compensation (amount)-Construction” or “Wage Bill-Construction”.

Response to Comment II-C:

Please see the response to Comment II-A.

Response to Comment II-D:

While the REMI model models capital investment using optimal capital stock theory, staff disagrees with its applicability for modeling the potential impact on current and future capital investment due to these proposed air pollution control amendments. Increments to capital investment, operating through the optimal capital stock mechanism, results in an appropriate modeled effect only when a facility is reasonably expected to lower its level of capital investment in the future by a similar amount spent on installing pollution control equipment. This can be the case in the situation where the affected facility has already planned on installing controls even without any policy interventions, and the effect of policy interventions would be to induce this investment made earlier in time. In terms of control installation under the RECLAIM program, staff does not consider this to be the appropriate situation, because absent clean air regulations and programs, a facility is not expected to make capital investments on pollution abatement. Staff also consulted with REMI staff, who agreed with staff's assessment.

In a letter from Kavet, Rockler & Associates dated November 19, 2015, the commenter maintained the opinion that "the nonresidential capital stock requires that the incremental value be included." Staff has already responded with the reasons why this is not always the case, especially not when it comes to capital spending on pollution control. Staff did not claim that the effect is insignificant, as incorrectly suggested by the commenter, but that it is an inappropriate modeling approach based on the theoretical foundation of optimal capital stock.

Response to Comment II-E:

REMI input files as requested were delivered via public record request on October 14, 2015. Kavet, Rocker, and Associates, LLC followed-up on this data request with a letter dated November 19, 2015 that presented their cost estimates using the REMI data sheets requested.

According to staff's estimates, the present worth value of control installation under the proposed rule amendments would amount to $728 million to $1.1 billion (in 2014 dollars). The high-end cost estimate (i.e., $1.1 billion) was used to annualize compliance costs and project macroeconomic impacts using the REMI model. However, it was not clear to staff how the commenter arrived at the conclusion that the total cost for the 2018-2035 period would be as high as $2.1 billion (in 2009 dollars) under the proposed rule amendments, or the "Proposed Project". One plausible explanation was that the commenter may have inadvertently double counted the compliance cost by adding up the same values assigned to both "Production Cost" and "Exogenous Final Demand" variables, which is a usual modeling practice to reflect the fact that one industry's compliance cost spending will benefit other industries that either manufacture control equipment or provide control installation related services.

III. GENERAL QUESTIONS AND/OR COMMENTS

Response to Comment III-A:
Staff believes that the compliance cost of control installation and the incremental compliance cost due to the effect of the NOx RTCs shave on the credit market are not the same in nature and should not be simply added. For example, the incremental compliance cost of purchasing additional RTCs could result in financial gains to a facility that installs cost-effective controls and thus has surplus NOx RTCs for sale. The financial gains would then offset the compliance cost of control installation. Therefore, simply adding up both categories of compliance costs could result in double counting.

Response to Comment III-B:

The Short-Term Economic Outlook section was provided at the request of stakeholders in order to assess the current state and overall health of the regional economy. This section presents the latest and credible economic forecast available by local economic development agencies and universities. Staff has also included a 10-year employment forecast by industry in Section 5: Short-term/Long-term Economic Outlook.

Response to Comment III-C:

Please see the following link for the 2015-2016 Economic Forecast and Industry Outlook from the Los Angeles Economic Development Corporation (LAEDC).
http://laedc.org/2015/02/18/2015-2016-economic-forecast-published/

Please use the following link for the report published by the California State University, Fullerton. The commenter may need to contact the department to receive the full report.
http://business.fullerton.edu/Center/EconomicAnalysisAndForecasting/#Default

Response to Comment III-D:

Staff will present the impacts of the proposed amendments on the relative cost of production and relative delivered prices in the Final Socioeconomic Report. Regarding the macroeconomic impact associated with the projected NOx RTC transaction, please see the response to Comment I-A.

Response to Comment III-E:

Staff has removed the reference to the refineries' global revenue.

Response to Comment III-F:

Regarding the comment on RTC acquisition cost, please see the response to Comment III-A.

Staff has added a caveat, stating that refineries may not be able to pass on the full cost of the proposed amendment to consumers due to possible outside competition from gasoline imports. However, it should be noted that due to clean air regulations, the gasoline blends sold in this region are different from those permitted in other parts of the country. Therefore, any outside competition, if any, is expected to be very limited.

ATTACHMENT K
PAST STATIONARY SOURCE COMMITTEE PRESENTATIONS

SEPTEMBER 23, 2015 (SPECIAL SESSION)

RECLAIM BARCT

Special Stationary Source Committee
September 23, 2015

Barbara Baird
Chief Deputy Counsel

RECLAIM BARCT

SCAQMD must adopt rules to require "best available retrofit control technology" (BARCT) for existing sources.

H & S Code § 40440(b)(1)

RECLAIM BARCT

BARCT is defined as:
an emission limitation based on the "maximum degree of reduction achievable" considering "environmental, energy and economic impacts. . ."

H & S § 40406

3

CARB Legal Opinion, 1992

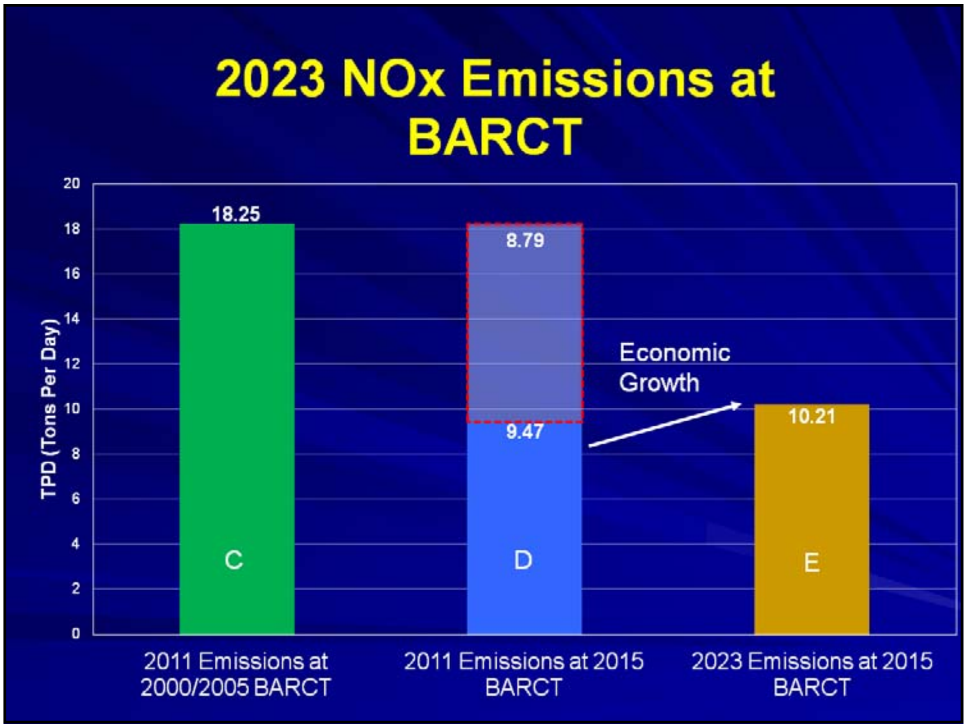
- BARCT can be met in the aggregate, including emissions trading
- But must be equivalent to what command-and-control would achieve
- Must be updated as technology advances

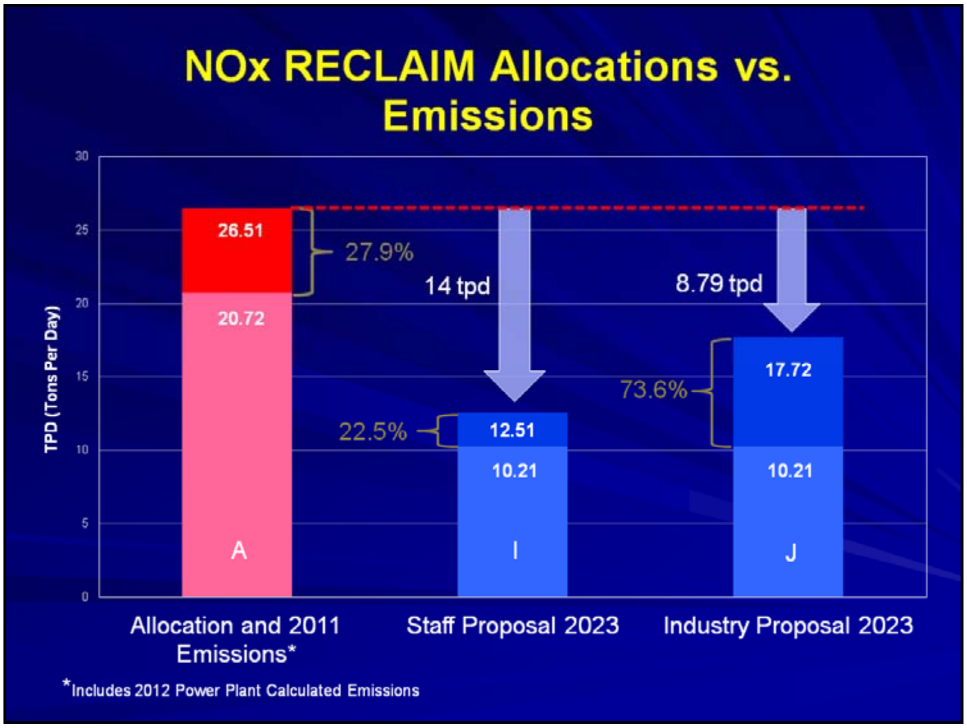
4

Industry Proposal

- Takes a goal derived from actual emission reductions, but then subtracts from allowable emissions
- Only guarantees small amount of actual reductions; rest are "paper reductions"

5





South Coast AQMD

Industry Proposal (cont'd)

- Is not designed to attain "maximum reductions achievable" as required by H & S § 40406
- Is not equivalent to levels that would be achieved under command-and-control
- Does not meet legal requirements

8

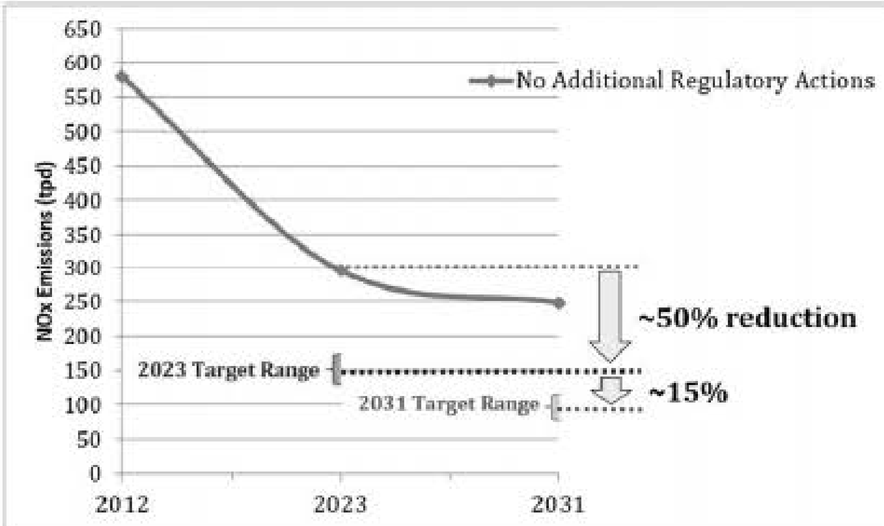
Proposed Amendments to Regulation XX – NOx RECLAIM Special Stationary Source Committee Meeting

September 23, 2015
SCAQMD
Diamond Bar, CA

Background – RECLAIM

- RECLAIM originally adopted in 1993
  - Establishes annual facility-wide emission limits for NOx and SOx
  - Allows emission trading amongst facilities
  - Subject to reduction of limits over time
- Compliance options
  - Install air pollution controls
  - Process changes
  - Purchasing of RECLAIM Trading Credits (RTCs) from other facilities and investors
- Last shave amendment was in 2005

Significant NOx Reductions Needed for Ozone and PM 2.5 Attainment



Equipment Categories Identified with Potential Further NOx Reductions

- Refinery Gas Turbines
- Metal Heat Treating Furnaces >150 MMBTU/hr
- Sodium Silicate Furnace
- Glass Melting Furnaces
- Non-Refinery Internal Combustion Engines (Non-Power Plant)
- Cement Kilns
- Refinery Fluid Catalytic Cracking Units
- Non-Refinery Gas Turbines (Non-Power Plant)
- Coke Calciner
- Refinery Boilers/Heaters
- Refinery Sulfur Recovery Units/Tail Gas Units

Working Group Meetings*

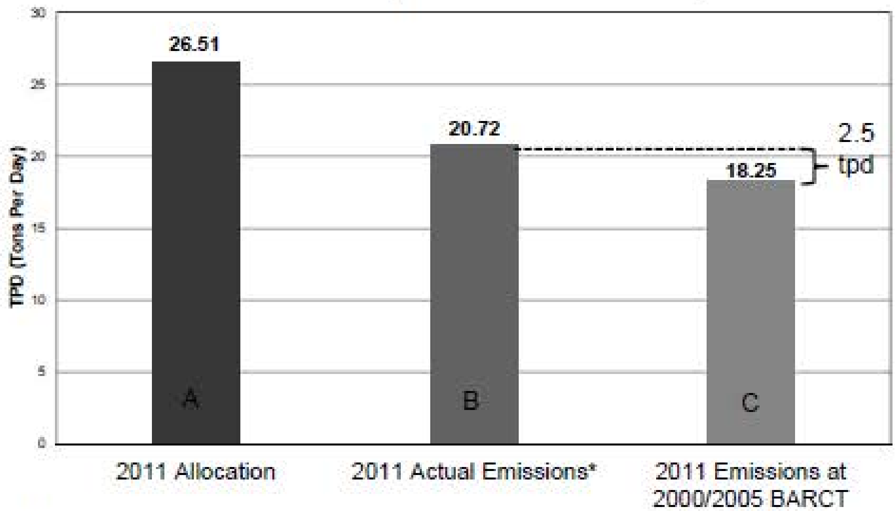
- January 31, 2013
- March 20, 2013
- June 13, 2013
- September 19, 2013
- January 22, 2014
- March 18, 2014
- July 31, 2014
- January 7, 2015
- April 29, 2015
- June 4, 2015
- July 9, 2015
- July 22, 2015 (Public Workshop)
- August 19, 2015

*Rulemaking Analysis initiated over 3 years ago

Major Proposed RECLAIM Amendments

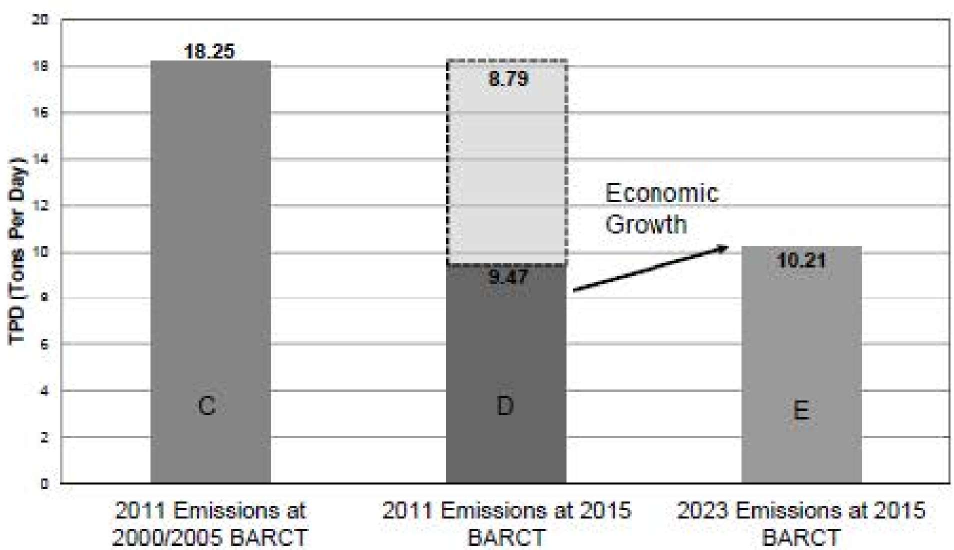
- BARCT Equivalency required by State law (H&SC § 40440 and § 40914)
- Total proposed RTC reductions = 14 tons per day based on BARCT analysis
- Updated BARCT emission factors
- Timing and distribution of shave
- Establishment of Adjustment Account for Power Plants

Comparison of NOx RECLAIM Emission Levels Relative to Total Allocation (2011 Base Year)

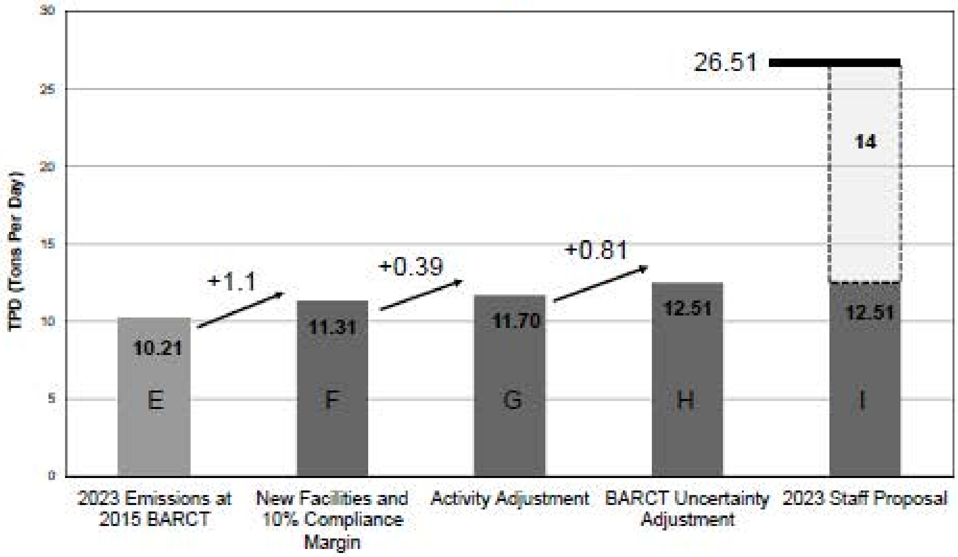


*Includes 2012 Power Plant Calculated Emissions

2023 NOx Emissions at BARCT



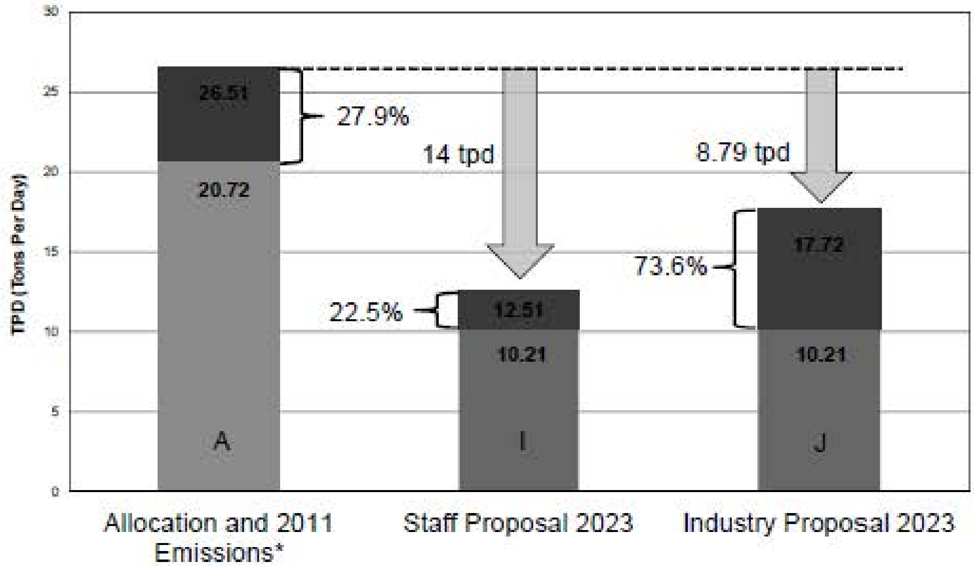
2023 Adjustments and Allocation Target



Key Issue: Amount of Shave

- BARCT Analysis
  - NEC Assumptions for Refinery Sector
  - SCAQMD Responses
    - Different approaches and engineering assumptions
    - No impact on proposed RTC reduction
    - Resulting 0.33 tpd difference less than proposed 0.81 tpd adjustment
- Industry proposal for shave amount (8.79 tpd)

NOx RECLAIM Allocations vs. Emissions



*Includes 2012 Power Plant Calculated Emissions

Timing/Distribution of Shave

- Staff Proposal: 14 ton per day RTC reduction
  - 4 tons per day reduced in 2016
  - Remainder to be reduced equally from 2018 to 2022
  - Proposed reductions based on share of BARCT opportunities
    - Refineries and Investors: 66%
    - Non-Refinery facilities and power plants among the top 90% of RTC holders: 47%
    - 210 facilities not among the top 90% of RTC holders: 0% Facilities)
- Key Issues
  - Sufficient time for engineering, permitting, procurement, and construction
  - Equity of shave distribution
  - Addressing refinery turnaround schedules

NSR for Natural Gas Power Plants

- Newer power producing facilities required by federal NSR regulations to hold RTCs to offset their potential to emit (PTE), even though actual emissions are well below this level
- Adjustment Account for newer power producing facilities (already required to be at BACT or BARCT)
  - Assist compliance with NSR holding requirements
  - To be held by SCAQMD regionally
  - Difference between pre- and post- shave holdings
  - Not to be used to offset actual emissions unless state of emergency regarding power supply is declared by the Governor

Key Issues regarding Adjustment Account

- Regional account or held by individual facilities
- Criteria to access RTCs to offset actual emissions

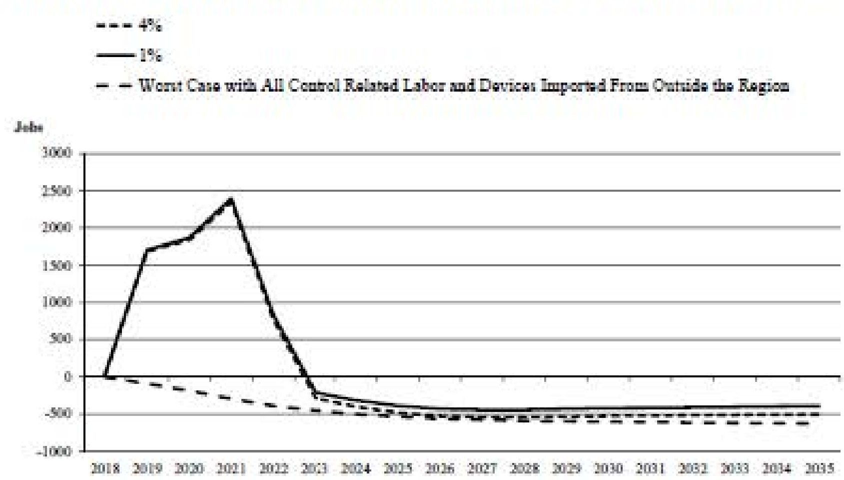
10-Year Equipment Life

- Industry believes 10-year equipment life is appropriate given frequency of RECLAIM amendments
- Equipment lasts 25 years, thus 25-year life is appropriate and consistent with SCAQMD past practices
- Little or no equipment was identified as obsolete or a stranded asset from the last shave in 2005
- Even with future NOx shaves, not all equipment becomes obsolete / stranded assets

15

Costs and Job Impact of BARCT Installation

- **Total Potential Cost: $0.62 – 1.09 Billion** **(100% control installation)**
- **Average Annual Costs: $52 – $63 MM**
- **Average Annual Job Impact: +13 to +90 (over 2018-2035)**
- **Not Expecting Shift from High-Pay to Low-Pay Jobs**



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ATTACHMENT L
PAST STATIONARY SOURCE COMMITTEE PRESENTATIONS

OCTOBER 16, 2015

Amendments to NOx RECLAIM Program

Stationary Source Committee

October 16, 2015

Purpose of Proposed NOx RECLAIM Amendments

1. Protect Public Health
   - Significant NOx reductions needed to attain Ozone and PM2.5 standards (50% additional reductions by 2023)
   - RECLAIM sources account for ~40% of all non-mobile source emissions
   - Proposed shave is a critical step towards healthful air quality and attainment
2. Meet Requirements of State Law (H&SC §40919)
   - All sources to implement BARCT

Approach

1. Technology Assessment - BARCT Analysis
   - Feasible and cost-effective controls
   - Consultants' review of staff analysis
2. Achieve equivalent emissions outcome as BARCT under Command-and-Control Regulations
   - Assume all feasible/cost-effective controls are implemented by 2023, including economic growth projections
   - BARCT-equivalent allowable NOx emissions in 2023 = 10.21 tpd
   - Add compliance margin, BARCT uncertainty adjustments, + 2.3 tpd
   - Total remaining NOx holdings in 2023 = 12.51 tpd
   - Current Holdings (26.51) - Shave (14) = Remaining (12.51)

Approach

3. Apply shave proportionate to identified BARCT opportunities
4. Implementation schedule considering the time needed to install equipment
5. Considerations for unique circumstances of Electrical Generating Facilities

SCAQMD Consultants' Analyses

- Two consultants (NEC and ETS) retained to review staff BARCT analysis
- Confirmed staff analysis and BARCT levels with few exceptions
- Staff adjusted approach based on consultants' findings
  - Coke Calciners (10 ppm), Cost Factors for boilers/heaters and SRU/TGU incinerators
- Only one exception (boilers and heaters) led to a 0.33 tpd difference
  - Staff included an adjustment (0.79 tpd) to the shave that more than covers the different engineering opinions for boilers and heaters

Industry Comments

Issue	Industry Claim	Staff Response
Proposal Goes "Beyond BARCT"	14 tpd emissions reduction goes beyond the BARCT analysis • 8.79 tpd is the BARCT adjustment • 5.21 tpd is Beyond BARCT 14 tpd	• Command and Control equivalency is 10.21 tpd remaining emissions in 2023 • A shave to achieve this level is BARCT, not "beyond BARCT"
Equipment Life	• Use of DCF method and 25-years useful life overstates cost effectiveness of controls • 10 years more appropriate	• Staff provides both DCF and LCF cost effectiveness estimates • Refineries acknowledge equipment lasts 25-years • Lifespan consistent with other agencies and EPA assessments • 10-year life assumes IF rule is amended in 10 years that ALL investments are stranded assets

Industry Comments

Issue	Industry Claim	Staff Response
RECLAIM Effectiveness	RECLAIM responsible for more NOx emissions reductions than non-RECLAIM sources: 6.4 TPD since 2005	• Past NOx reductions depend on where the feasible, cost-effective opportunities are • ~1/3 of these RECLAIM reductions derive from shut down facilities • Under command and control, shut downs result in very limited ERCs

Cost Effectiveness Threshold	CE threshold of $50,000/ton is more than twice that used for command and control rules	• Used same CE threshold for SOx RECLAIM, not adjusted for inflation over 7 years
		• Average Incremental CE:
		  • Refinery Sector : $ 10,000/ton - $17,000/ton
		  • Non-Refinery Sector: $9,000/ton - $14,000/ton

Industry Comments

Issue	Industry Claim	Staff Response
The Gap Between Allocations and Actual Emissions Should be Much Larger than the Staff Proposal	Gap important for market function, includes compliance margin, growth, investor holdings, & RTCs for new facilities and structural buyers	• Staff proposal includes 10% compliance margin, adjustments, and growth projections for existing and new businesses • Resulting 23% gap is sufficient and consistent with past gaps in a functioning market

General Industry Comment:
Too Much, Too Fast, for the Market to Function

- Rule has safeguards to ensure market functioning
- Staff continuing work with industry on
  - Implementation schedule
  - Temporary off-ramp based on shorter-term price trigger
  - Access to credits for power plants during power crisis
  - Resolution language to track electricity supply/demand relative to increased renewables and electrified transportation sector
  - Lower emission rates for R219 exempt equipment

Proposal Comparison

Staff Proposal	Industry Proposal (10/14/15)
• 14 TPD shave • 12.51 TPD remaining RTCs	• 10.3 TPD • 16.21 TPD remaining RTCs
Implementation Schedule 4, 0, 2, 2, 2, 2, 2	Delayed Implementation Schedule Less in first year, weighted towards end years
$22,500/ton Running Annual Average threshold	Shorter trigger time necessary (e.g. six months, ….)

Summary

- Primary issue is size and schedule of shave
- Continue working with stakeholders to finalize provisions for program safeguards
- Staff is prepared for November Public Hearing

ATTACHMENT M
PAST STATIONARY SOURCE COMMITTEE PRESENTATIONS

NOVEMBER 20, 2015

Proposed Amendments to Regulation XX – NOx RECLAIM Stationary Source Committee Meeting

November 20, 2015

Purpose

- Meet requirements of state law
  - SCAQMD shall require BARCT for existing sources(H&SC § 40440)
  - All feasible measures (H&SC § 40914)
- 2012 AQMP control measure CMB-01
- Significant NOx reductions needed for ozone and PM 2.5 attainment
- Level the playing field
  - RTC price significantly lower than C&C control costs for mobile sources and other stationary sources
- To demonstrate our fair share reductions while demanding CARB & EPA to do their fair share

Market Program vs. Command & Control

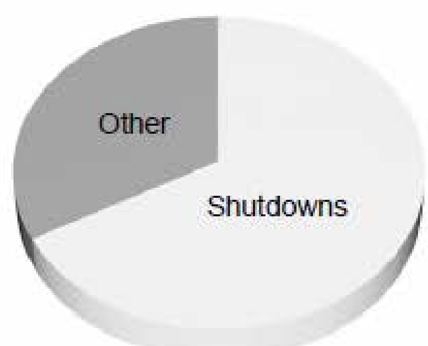
- Market Program
  - Low hanging fruit picked first
  - Flexibility/Options
  - Cost savings
- Command and Control:
  - All the fruit gets picked
  - Limited flexibility

In SCAQMD, eventually, both approaches converge.
All the fruit is gone

Emission Reductions From 2005 Amendment

NOx shave target = 7.7 tpd

- Actual emission reductions between 2006-2012 = 4 tpd
  - 2.6 tpd (65%) from shutdowns
  - 1.4 tpd (35%) from controls, process changes, recessionary production levels
- If C&C, all reductions would have occurred



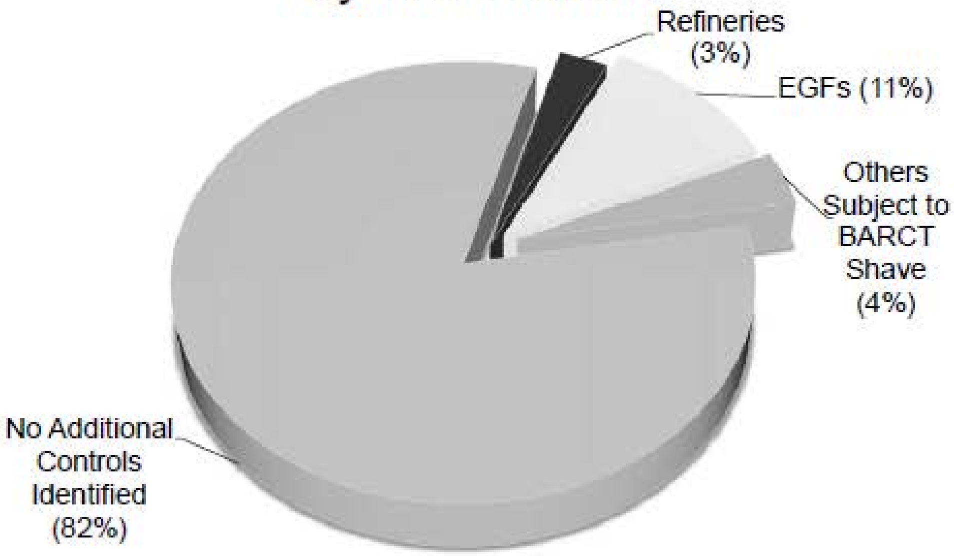
Why Retire RTCs from Shutdowns?

- Command and Control Shutdowns
  - Credits discounted to BACT and based on last 2 yrs. of operation
- RECLAIM Shutdowns
  - No discount of credits
  - Financial incentive for shutdowns and job loss
  - Reduces incentive to implement cost-effective controls that would be required under command and control

Why Allow EGFs to Opt-out of RECLAIM?

- Electrical grid system has changed over time
- EGFs are unique
  - Once-Through Cooling Regulation – older units repowered with cleaner, more efficient units
- EGFs highly regulated
- Most units already at BARCT or BACT
- Provide essential public service
  - Other essential public services exempt from RECLAIM
- Need to hold extra RTCs for NSR and/or to meet resource adequacy

Facility Distribution
by # of Facilities



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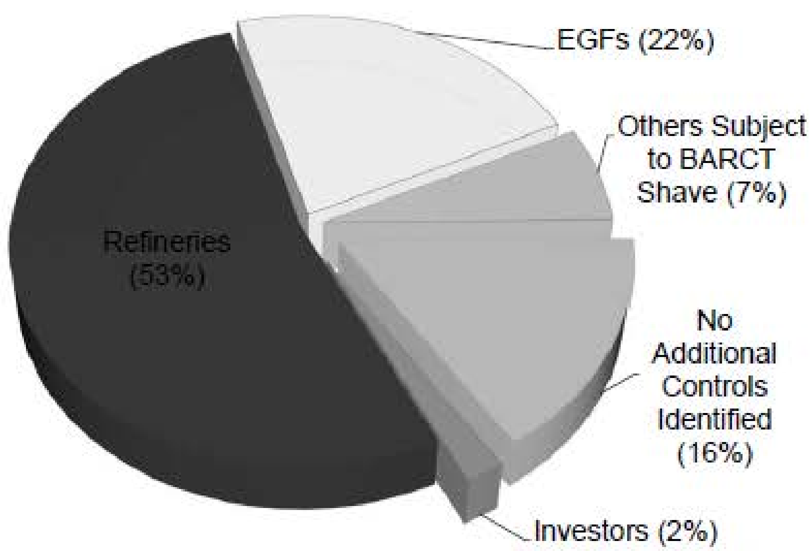
RTC Holding Distribution
As of Freeze Date



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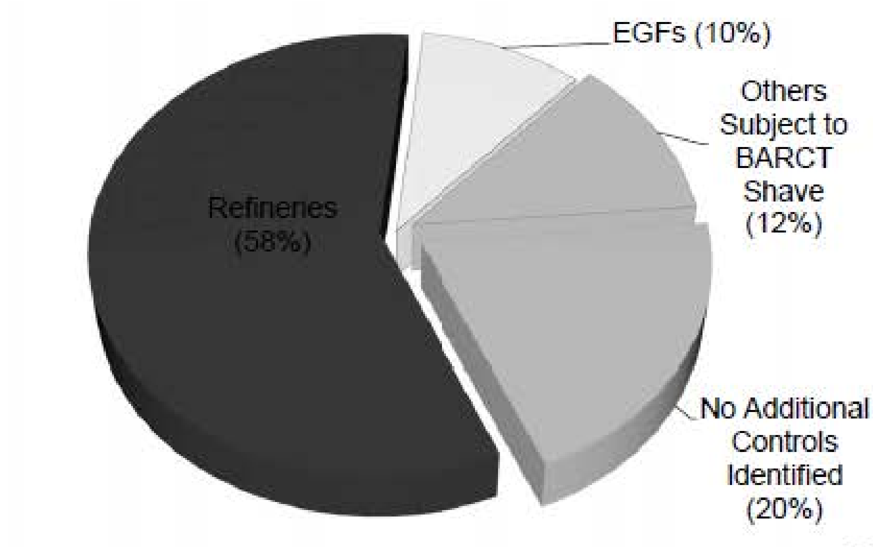
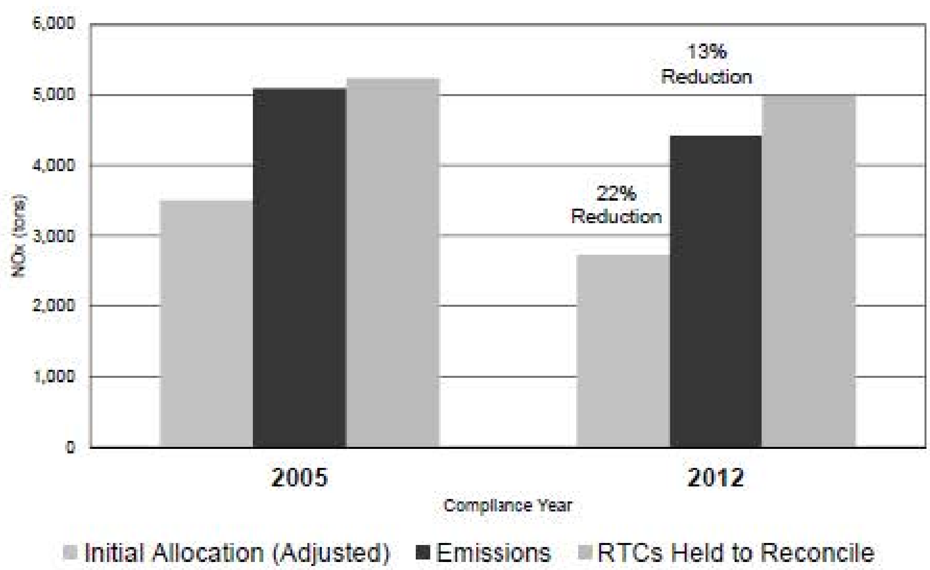
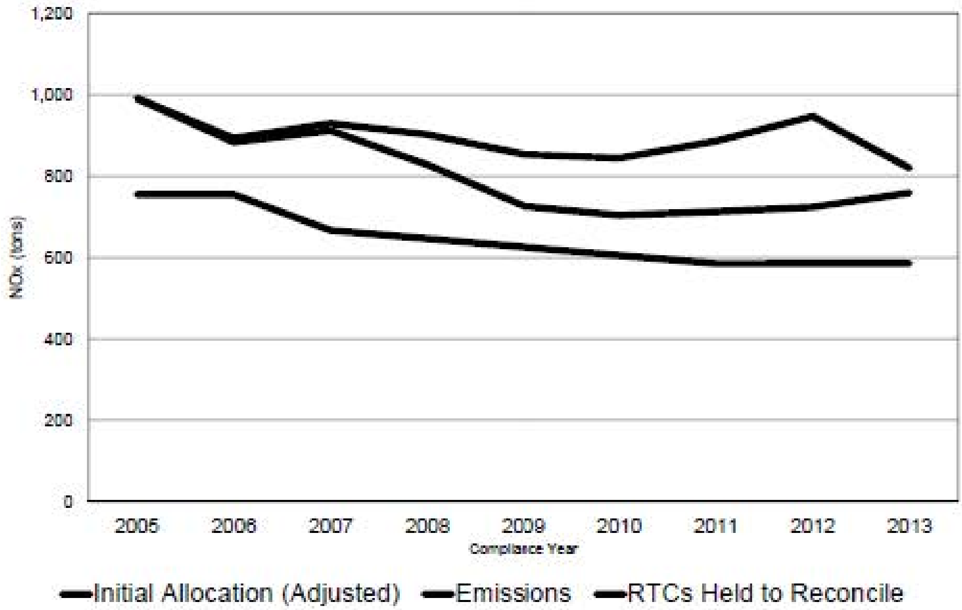
Facility Distribution
2013 Emissions



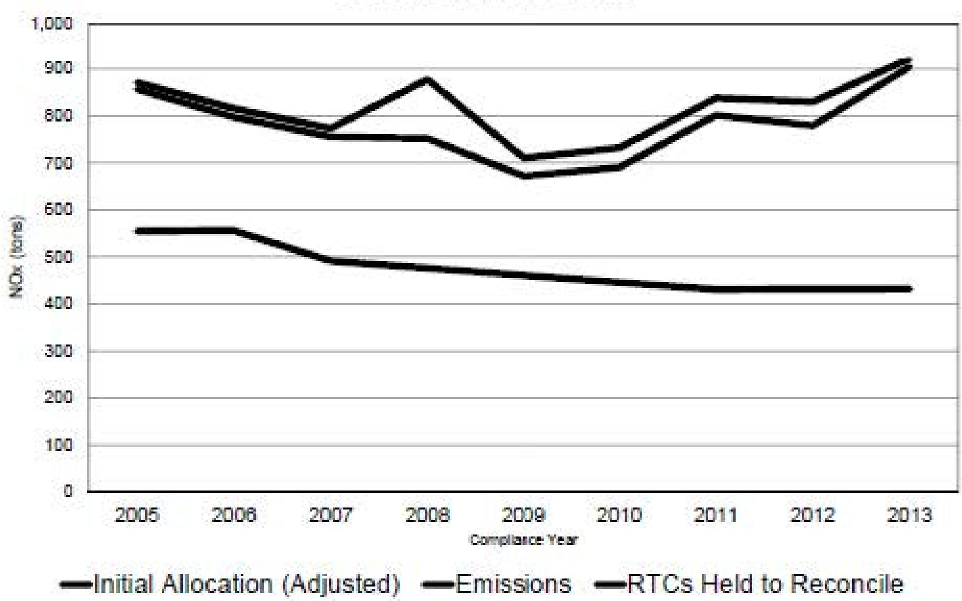
Aggregate Refinery Totals



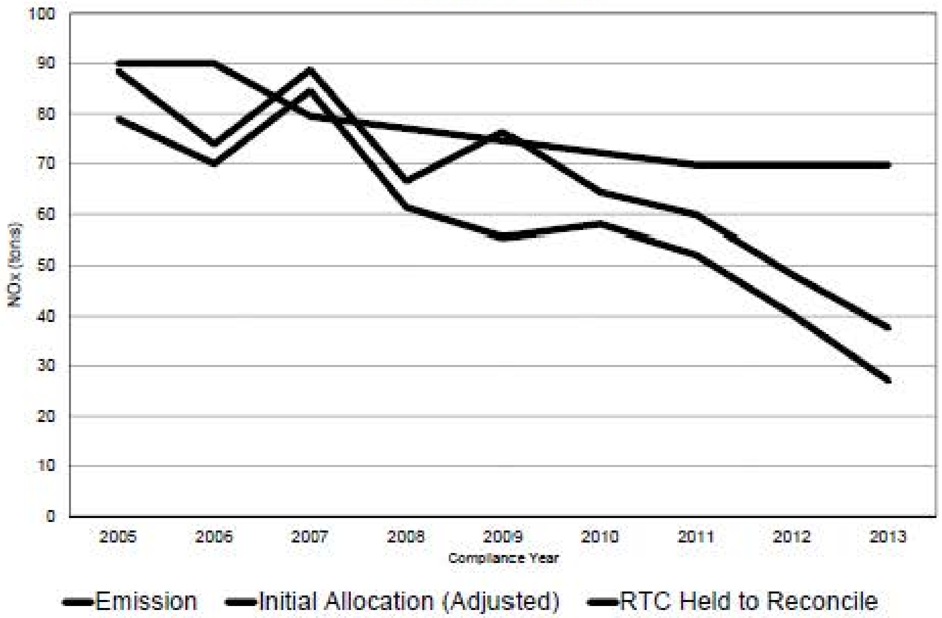
Chevron



ExxonMobil



Paramount



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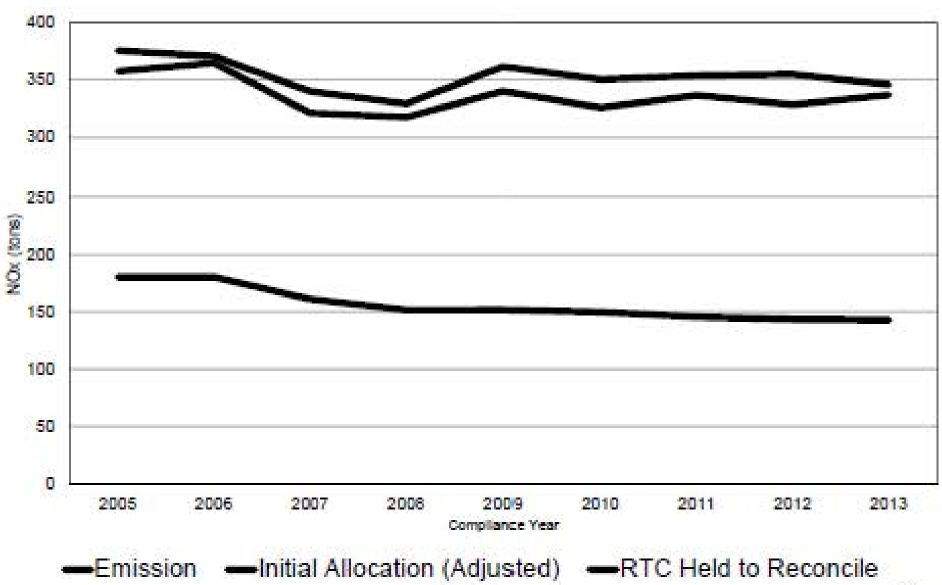
Phillips 66 Carson



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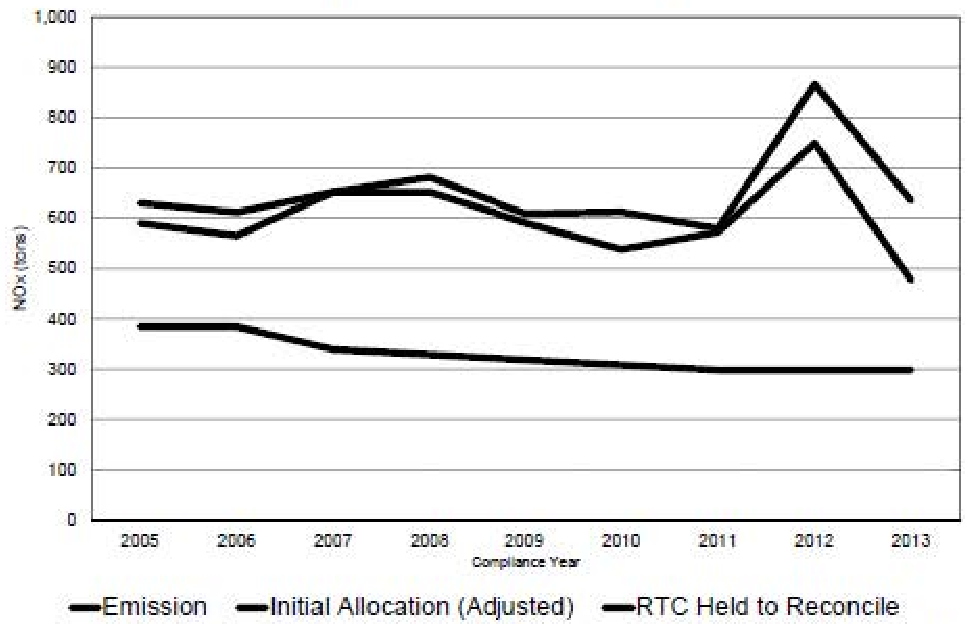
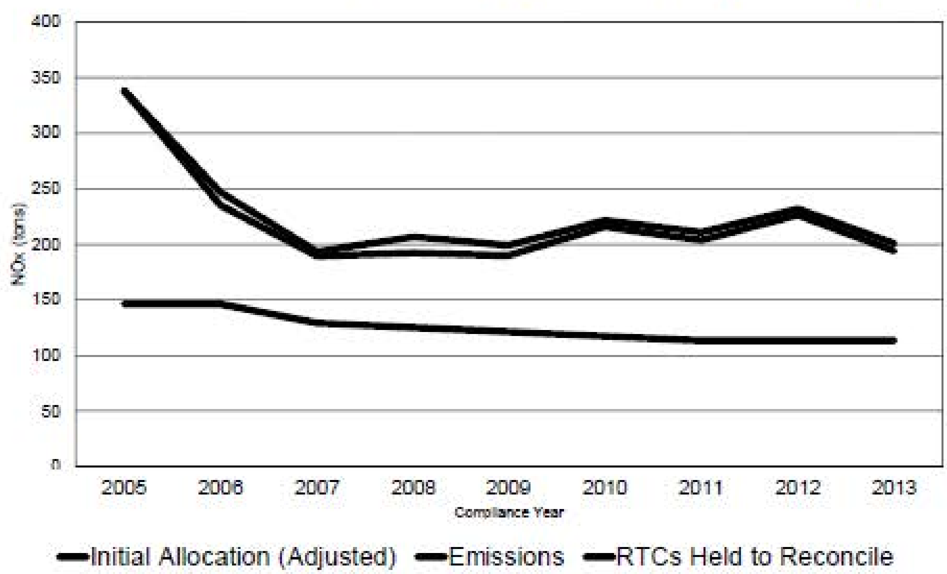
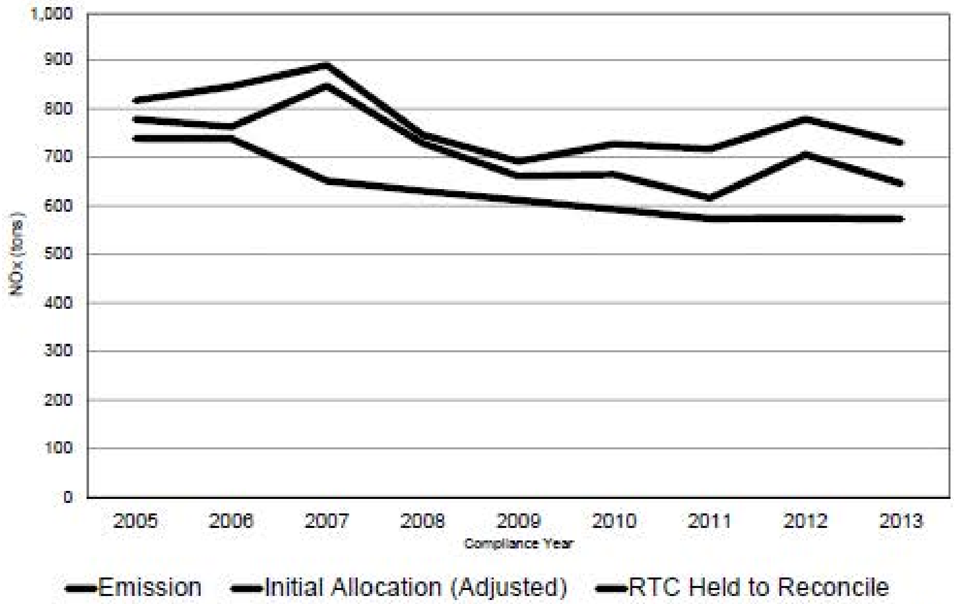
Phillips 66 Wilmington



Tesoro Calciner (Formerly BP)



Tesoro Carson (Formerly BP)



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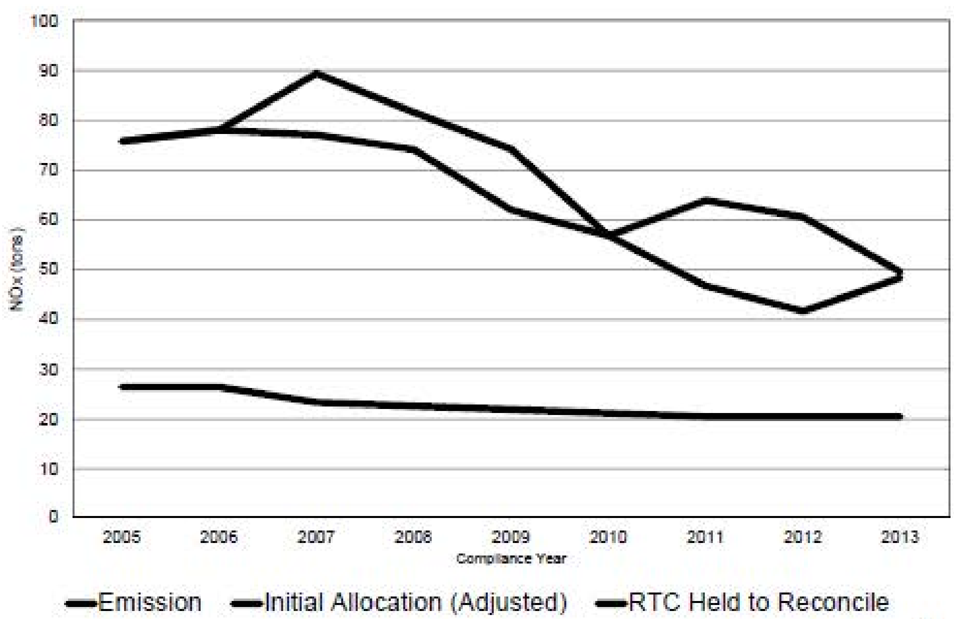
Tesoro SRU



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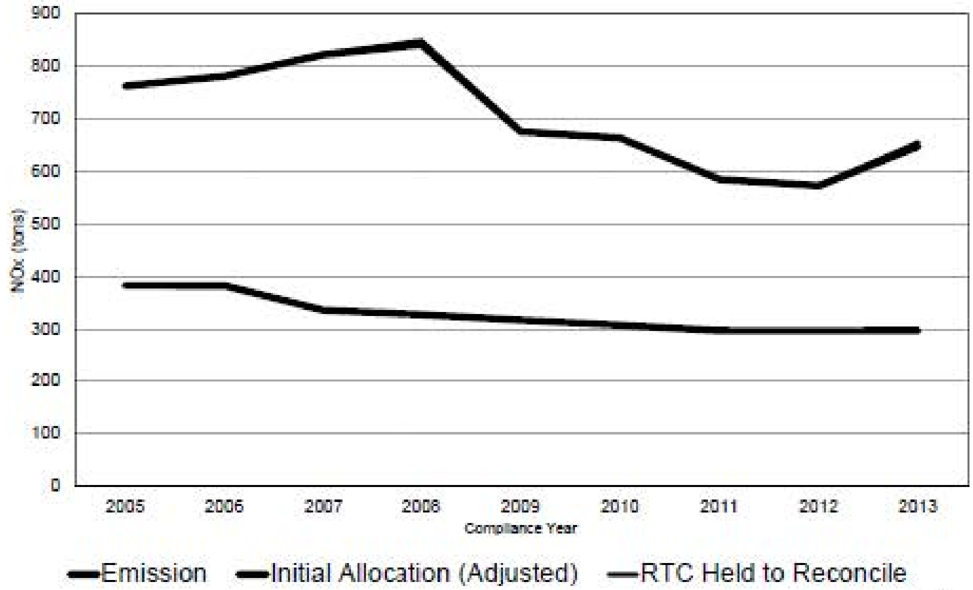
Tesoro Wilmington



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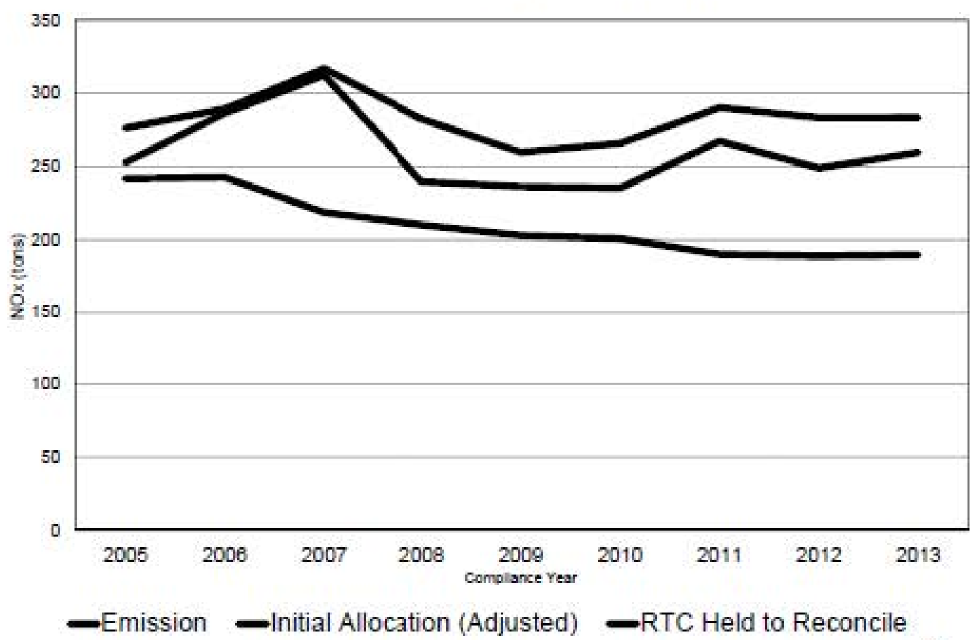
Ultramar (Valero)



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WSPA Comments

- Staff did not address discrepancies identified in NEC Report
  - Incorrect understanding of staff approach
  - 0.33 tpd difference
  - 0.8 tpd adjustment included in proposal
- $2.3 Billion vs. $0.7 – $1.1 Billion Cost
  - Insufficient details provided to assess validity
  - Incremental cost vs. total cost
    - Staff assumed controls from last shave in place
    - Significant accrued cost savings from delayed controls

WSPA Comments

- 10 year equipment life, DCF vs LCF
  - Staff provides both DCF and LCF cost effectiveness estimates
  - Refineries acknowledge equipment lasts 25-years
  - Lifespan consistent with other agencies and EPA assessments
  - 10-year life assumes IF rule is amended within 10 years that ALL investments are stranded assets *(impossible outcome)*

Proposed Regulation XX

- Stakeholder Comment
  - Recent changes to the rule (opt-out for EGFs and shutdown provisions) have not been analyzed for impacts and necessitates a delay in the rule amendment

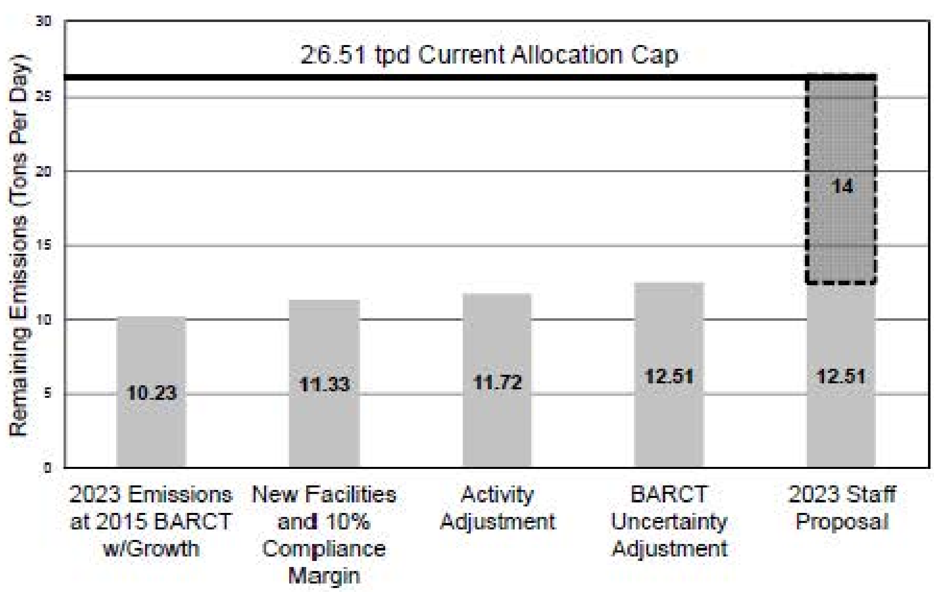
Proposed Regulation XX: Staff Response

- EGF opt-out
  - EGFs will only opt out if it is to their advantage and are at BARCT or BACT
  - Better grid reliability
- Shutdowns
  - Removal of shutdown credits needed to achieve BARCT equivalency
  - Under command and control, shutdown credits are deeply discounted and restricted

Proposed Regulation XX: Staff Response

- Both provisions
  - Not expected to have environmental or economic impacts beyond those already analyzed
  - Already conducted multiple meetings with stakeholders
  - Working Group Meeting next week
  - Beneficial for AQMP
  - Safety valves in rule if RTC price reaches trigger levels

14 tpd Feasible and Necessary



ATTACHMENT N
PAST STATIONARY SOURCE COMMITTEE PRESENTATIONS
INDUSTRY RECLAIM COALITION

SEPTEMBER 23, 2015 (SPECIAL SESSION)

Industry RECLAIM Coalition

California Asphalt Pavement Association (CalAPA)
California Construction & Industrial Materials Association (CalCIMA)
California Council for Environmental and Economic Balance (CCEEB)
California Manufacturers & Technology Association (CMTA)
California Metals Coalition (CMC)
California Small Business Alliance (CSBA)
Regulatory Flexibility Group (RFG)
Southern California Air Quality Alliance (SCAQA)
Western States Petroleum Association (WSPA)

Los Angeles Business Federation (BizFed)*
***Representing 272,000 businesses - employing 3 million people**

NOx RECLAIM Shave

23 September 2015

1

Industry Coalition's Objectives

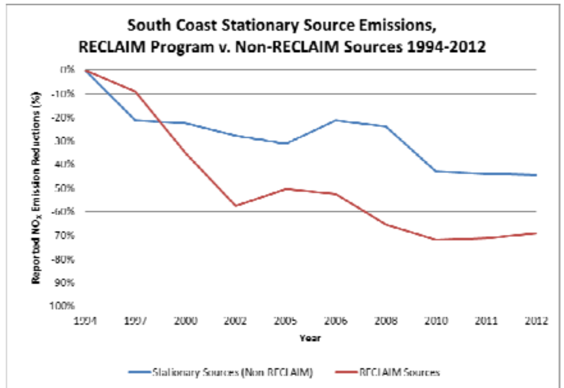
- Preserve a successful program and a healthy RECLAIM market
- Reflect the emission reductions possible from advancements in BARCT between 2005 and 2015 (Technology Shave)
- Fulfill obligations in H&SC §39616(c) as opposed to the District's proposal which goes **beyond BARCT**
- Fulfill at a minimum the 2012 AQMP commitments to the State Implementation Plan (SIP) and USEPA
  - 3 to 5 tons per day NOx
- Recognize successful emission reductions from RECLAIM Program's 2005 shave

2

Emissions for RECLAIM facilities have declined faster than South Coast facilities under command & control rules (i.e., non-RECLAIM sources)

RECLAIM program's emissions have been reduced 69% since 1994

Non-RECLAIM stationary source emissions declined by about 44% during that same period



Sources: "RECLAIM Sources" data is reported (audited) emissions from SCAQMD RECLAIM Audit Report (March 2015). "Stationary Sources (Non-RECLAIM)" is taken from SCAQMD Air Quality Management Plans (1997, 2003, 2007, 2012) and AQMP Working Group Meeting #5, Agenda Item #3.

Legal Requirements

- Allows facilities the "flexibility to achieve emission reductions using methods which include, but are not limited to: add-on controls, equipment modifications, reformulated products, operational changes, shutdowns, and the purchase of excess emission reductions." [1]
- CA Health & Safety Code (H&SC) §39616(c) requires on a program basis:
  - equal or greater emission reductions than command-and-control
  - equal or less cost than command-and-control
- Under the 2005 market adjustment, a 23% reduction in RTCs resulted in a 24% reduction in NOx RECLAIM emissions [2]
- The District is going **BEYOND BARCT**

[1] Source: SCAQMD Rue 2000(a).
[2] Source: SCAQMD Annual RECLAIM Audit Report, March 2015.

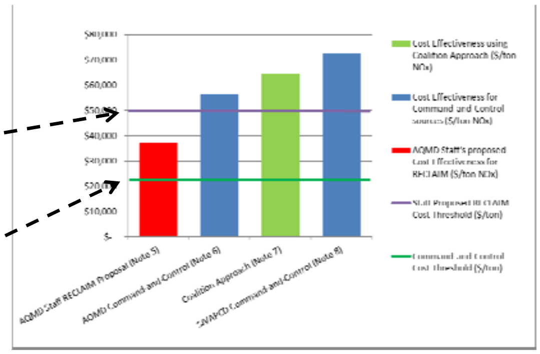
Staff Proposal would treat RECLAIM disproportionately as compared to Command-and-Control

RECLAIM program is required to be equivalent or less costly than command-and-control rules [1]

AQMD use of DCF method and 25-year useful life overstates cost-effectiveness of controls [2]

Staff are proposing a cost effectiveness threshold that is twice that used for AQMD's command-and-control rules [3]

Cost effectiveness threshold for this rule should be the same one used for command-and-control rules; $22,500 per ton [4]



Example is $5M emission control project with 25 tpy NOx reduced. Notes: (1) H&SC 39616(c)(1). (2) Comparison of AQMD Staff method proposed v. AQMD BACT method. (3) Comparison of SCAQMD cost threshold in 2012 AQMP and 2015 RECLAIM. (4) SCAQMD 2012 AQMP. (5) AQMD Staff method proposed for RECLAIM in Preliminary Draft Staff Report (July 2015) using DCF method, 25-year Useful Life assumption, and 4% interest rate. (6) AQMD BACT Guidelines, Part C (2006) using DCF method, 10-year Useful Life assumption, and 4% interest rate. (7) Industry Coalition proposed method using LCF method, 10-year Useful Life, and 4% interest rate. (8) SJVAPCD BACT Guidelines.

5

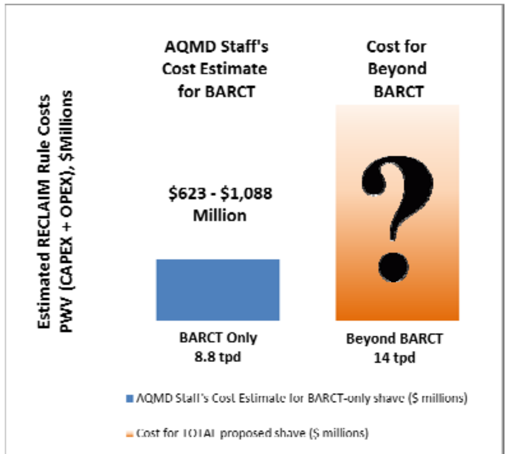
Command and Control Equivalency is not more than 6.6 TPD

- AQMD Staff's current analysis only demonstrates 7.9 TPD of reductions can be justified by technology advancement (i.e. BARCT) [1]
- AQMD Staff have not reconciled the discrepancies between their cost analysis and the recommendations of the third-party expert, Norton Engineering
- The Industry Coalition further believes corrections to the AQMD Staff's cost effectiveness methodology would trim BARCT reductions by an estimated 1.3 tpd [2]
- A reduction greater than 6.6 TPD would be **BEYOND BARCT**

1 AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 18. Presented BARCT reduction adjusted pursuant Staff's 0.85 TPD adjustment factor to account for discrepancies between Staff analysis and third-party expert, Norton Engineering.
2 Industry Coalition/ERM analysis of AQMD BARCT calculations assuming a 10-year useful equipment life (Sept 2015).

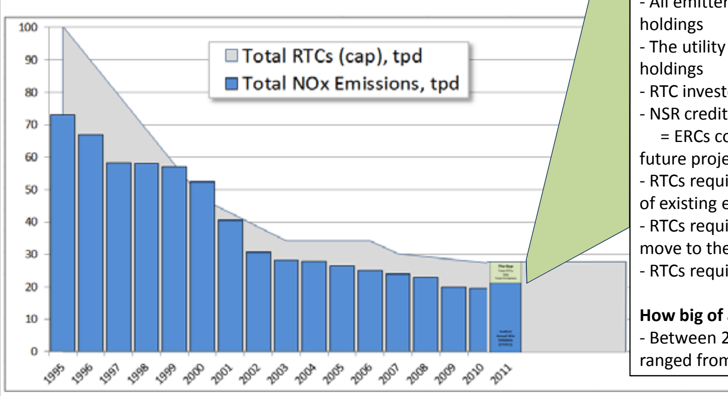
6

BARCT $ ≠ BARCT $ + BEYOND BARCT



Sources: "AQMD Staff's Estimate for BARCT-Only Shave taken from SCAQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, p. 23-24. To date, AQMD Staff have not provided a "Cost Estimate for the TOTAL proposed shave" of 14 tpd.

Mind the "Gap"



What is The Gap?
- The difference between the total RTCs issued and the total actual emissions.

What is in the Gap?
- All emitter's compliance margin holdings
- The utility sector's potential-to-emit holdings
- RTC investors' holdings
- NSR credits
  = ERCs converted to RTCs for future projects
- RTCs required for economic growth of existing emitters
- RTCs required for new businesses to move to the South Coast
- RTCs required for structural buyers

How big of a Gap is needed?
- Between 2005 – 2013, unused RTCs ranged from 5.1 to 9.1 tpd

[1] Source: SCAQMD, Annual RECLAIM Audit Report

Arbitrary Removal of RTCs

- CMB-01 Phase 1 (approved in the 2012 AQMP) explicitly considered and rejected removal of all RTCs in excess of actual emissions, except what was needed for the $PM_{2.5}$ contingency measure (2 tpd)[1]
- The proposed "compliance margin" of 10% is not adequate to meet the market's historical need for RTCs which have averaged in the 15-30% (5 to 9 TPD) range (except for the early 2000's power crisis) [2]
- The Industry Coalition approach negates the need for a "compliance margin"

[1] Source: SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.

[2] Source: SCAQMD, Annual RECLAIM Audit Report for 2013 Compliance Year, 6 March 2015. See Table 3-2.

Shave Implementation Schedule

- A shave of 4 TPD in 2 months does not allow adequate time for industry to install emission control projects which take several years to design, permit and implement[1]
- It also conflicts with CMB-01 Phase 1 which explicitly considered and rejected removal of all RTCs in excess of actual emissions, except what was needed for the $PM_{2.5}$ contingency measure (2 tpd)[2]
- The Industry Coalition supports a schedule consistent with approved Control Measure CMB-01 Phase 1, which begins with 2 tpd in the first year

[1]Source: Industry Coalition letter to SCAQMD, August 21, 2015, p. 2.

[2]Source: SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.

Summary of Concerns

- Size of the proposed District shave could imperil the RECLAIM program
  - Shave is well beyond amount indicated by BARCT analysis
  - Depth of District's proposed shave potentially requires market to function with amount of "unused" RTCs only seen during the power crisis
- Shave Implementation schedule is too aggressive
- District BARCT analysis is flawed
  - Staff has selectively disregarded the recommendations of Norton Engineering, the AQMD's third-party consultant
  - Inappropriately equates BARCT with BACT
  - Assumes technology will develop in extremely short timeframe and w/o safeguards provided under command and control rules
  - Understates true cost by assuming 25-year equipment life
  - Corrections to the BARCT analysis could reduce the 8.8 TPD by approximately 2 TPD

Please support:

- The Industry Coalition alternative technology shave
- A feasible and cost effective BARCT assessment including a 10 year useful life
- A reasonable and achievable implementation schedule

ATTACHMENT O
PAST STATIONARY SOURCE COMMITTEE PRESENTATIONS
ENVIRONMENTAL COMMUNITY

SEPTEMBER 23, 2015 (SPECIAL SESSION)

South Coast AQMD Rule XX

Stationary Source Committee

September 23, 2015

Health Advocates Position

- Rule is a good step towards fixing a flawed program
- Strong rule realizes a previous commitment to near term reductions.
- Emission reductions should total *at least* 14.85 tons.
- Timeline for reductions should be faster
- Focus on refineries and power plants
- Industry concerns don’t hold water

Background

- South Coast facing steep reductions to meet 2023, 2032 NOx standards
- Missed 2010 1-hr standard
- Dirty air still plagues region
  - 1.1 million missed school days
  - 5,000 premature deaths
- Impact of dirty air inequitable

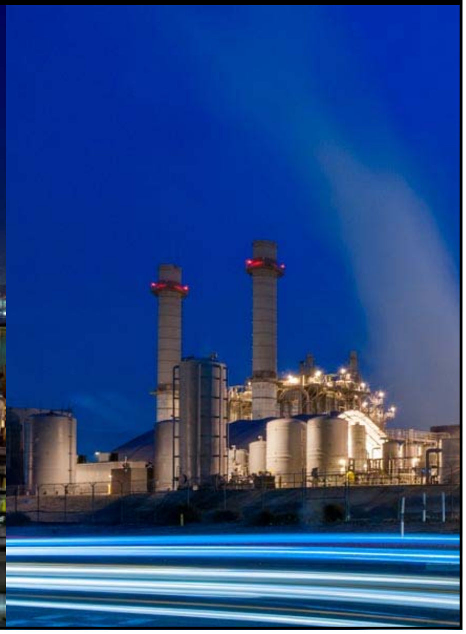
Cal. Health & Safety Code §39616.

- *"The program will result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment."*
- Proposal should shave *at least* 14.85 tons per day.

The need for reductions is urgent

Year	Current Proposal	Health Advocates Proposal
2016	4 tpd	5 tpd
2018	2 tpd	3 tpd
2019	2 tpd	3 tpd
2020	2 tpd	2 tpd
2021	2 tpd	1.85 tpd
2022	2 tpd	0 tpd

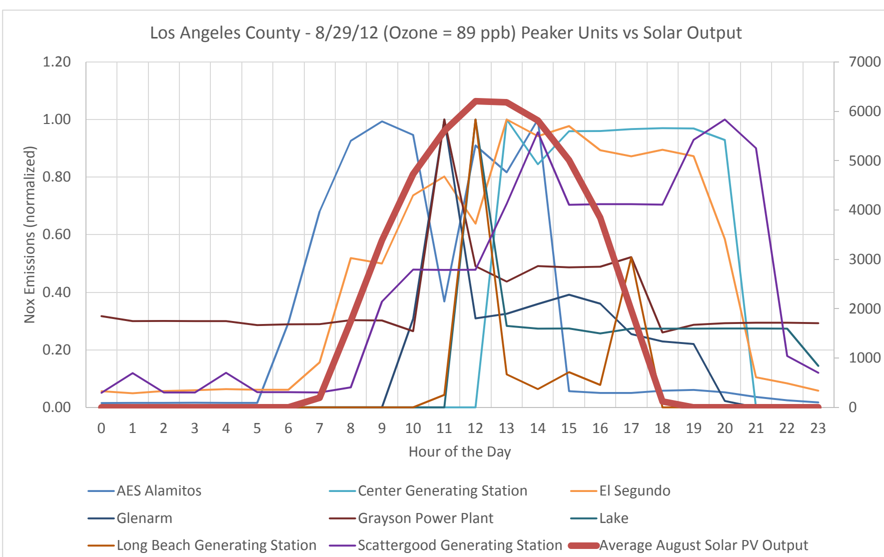
Focus on refineries & power plants



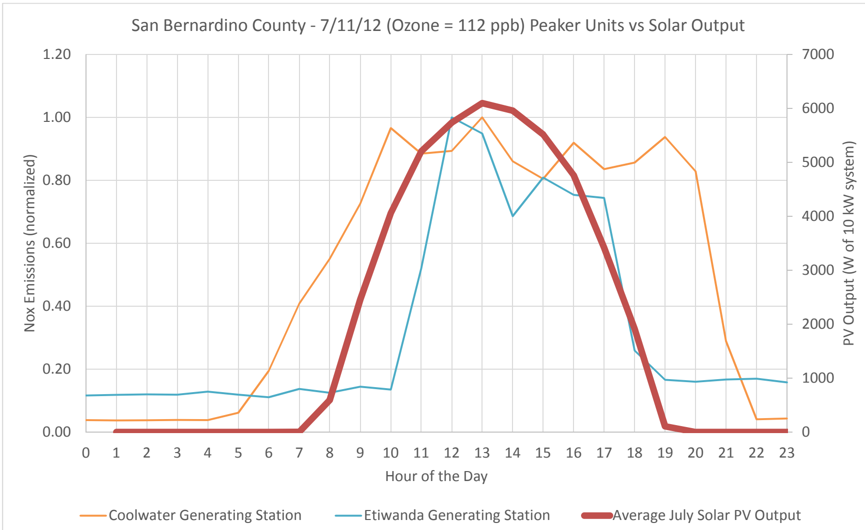
The Current Gas Boom

- Many power projects proposed for region:
  - Stanton Energy Reliability Center (98 MW)
  - Haynes (600 MW)
  - Harbor (449 MW)
  - Scattergood Generating Station (830 MW)
  - San Gabriel Generating Station (656 MW)
  - Huntington Beach/Alamitos (1,234 MW)
  - Sun Valley Energy Project (500 MW)

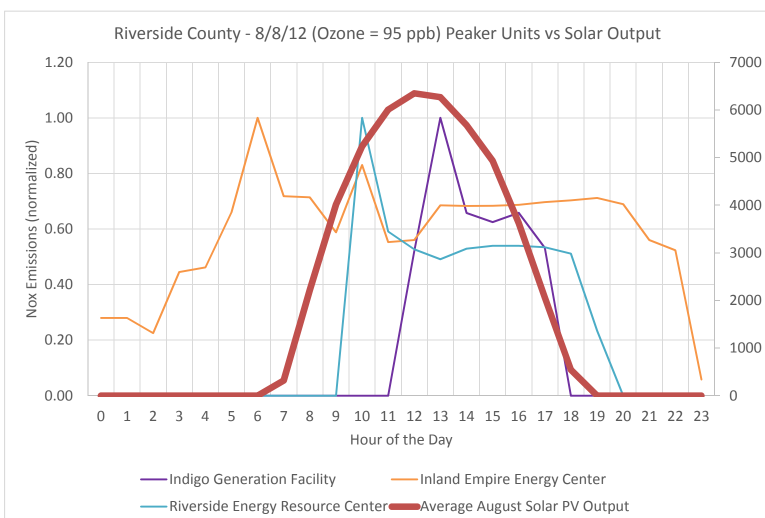
NOx, Gas Plants, and Solar Potential



Ozone, Gas, and Solar (cont'd)



Ozone, Gas, and Solar (cont'd)



Thank You

Addendum to Item #30 –
Amend Regulation XX - Regional Clean Air Incentives Market (RECLAIM)

This item includes:

1. Staff Report – The copies of Comment Letters that were part of the 30-day Set Hearing package were inadvertently omitted from the package that was released on Saturday, November 28th. Nonetheless, the responses to these comments were correctly included in both the 30-day Set Hearing package and the package released on Saturday, November 28th. The comment letters are attached.
2. Final Program Environmental Assessment – The online version of some CEQA comment letters is missing brackets from seven pages of the CEQA document (Appendix I: pages I-11, I-15, I-31, I-43, I-44, I-129 and I-130). The comment letters and responses to these comments were correctly included in the package released on Saturday, November 28th. These pages are attached with the brackets inserted.

Attachment to Appendix Z

Comment Letters #2 - #19

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August 10, 2015

Philip M. Fine, PhD
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South Coast Air Quality Management District
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Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for FCCUs
Document No. 14-045-7

Dear Mr. Fine,

We have completed a first pass review of the above captioned report's discussion of SCR applications to district SCRs and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on FCCU SCR Costs

Appendix F presents a review of NEC's analysis for FCCU SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommends using three catalyst beds and designing for superficial gas velocities of 10 ft/sec vs SCR vendor proposals which have less catalyst and 20% higher superficial velocities.

- NEC conditions budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment. This is characterized by staff as: "Adding a "mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs".

- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: "Adding another 75% increase in labor to the costs of the manufacturer's SCR.".

- NEC used incorrect FCCU feed rates in developing comparisons to AQMD PWVs.

The following paragraphs address each of staff's objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report.

Basis for Catalyst Addition and
Velocity Reductions vs Vendor Budget Quotes

All FCCU SCR catalyst beds are in the range of 3 - 4' deep, all are prone to plugging by catalyst and/or ABS and all have limitations on allowable pressure drop, so superficial velocity is a good basis for comparison between units. The district has three operating FCCU SCRs. All units have two catalyst beds and operate at superficial gas velocities in the range of 8 to 13 ft/sec. Two of the three units, operating at superficial velocities of 12 and 13 ft/sec do not achieve emissions of 2 vppm @ 3% O_2. The other unit, highlighted in the draft report, achieves less than 2 vppm @ 3% O_2 operating at a superficial velocity of 7.7 ft/sec. The "good" unit is operating with inlet NOx levels which are 50%

of design or lower and at lower than design flue gas flows. There are several ways to bring the two "non-performing" units into compliance with the revised standard, each with different costs and different overall performance impacts. NEC was not commissioned to do an evaluation of individual units and propose improvement options, but rather to make an assessment of what it would take, cost wise, to reliably achieve the 2 ppmv limit for grass roots SCR installations. Based on the experience of operating units in the district, and our direct experience with FCCU units for other clients (due to confidentiality agreements we cannot divulge client identities and specific locations) reliably achieving 2 vppm NOx emissions in an FCCU over a five year run will require the addition of catalyst and will be designed for superficial velocities of 10 ft/sec or less. Considering that SCR catalyst vendors have not developed and guaranteed a specific SCR design for 2 ppmvd @ 3% O_2 NEC feels that it is prudent to assume that a third bed of catalyst (SCR or ASC) and cross section designed to achieve a maximum superficial velocity of 10 ft/sec is sufficient to characterize the most likely cost of a SCR unit capable of achieving 2 ppmvd in a typical refinery FCCU environment. *The impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation has been overstated by district staff as a 284% increase in catalyst volume over manufacturer's estimates. The increase over manufacturer's budget estimates/proposals is actually 92%, one half of staff's reported delta.*

Staff's SCR Design Comparison Did Not Accurately Reflect NEC's "Typical" FCCU SCR Design

Staff used an incorrect basis for comparing NEC's typical FCCU SCR with district units in Table F.3. A revised comparison, using data from Refineries 1, 5 and 6 is shown below.

Table 1 (F. 3 Showing NEC Typical SCR)
Performance Information of Existing SCRs

	Refinery 1	Refinery 5	Refinery 6	NEC Typical
FCC Feed Rate, kBPD	95	71	84	55
SCR Inlet Flue Gas Flow, ACFS	6,585	5,525	9,685	3,848
SCR Manufacturer	1	3	2	--
No. Catalyst Layers	2	2	2	3
Catalyst Volume, ft^3	6,200	2,975(1)	6,200(5)	4,600
Design Inlet NOx, ppmv	133(2)/40-80(3)	150	35	45
Design Outlet NOx, ppmvd	--	17	6	2
NOx Measured, ppmvd	<2	15-17	5.6 – 6.4	1.5 (Est.)
Superficial Gas Velocity, fps	7.4	13.3	11.6	10.0
Space Velocity, 1/hr	3,823(6)	6,686(4)	5,624(5)	3,011
Removal Efficiency	95 - 97%(3)	89%	83%	97%

Notes:

1. Staff incorrectly stated catalyst volume as 2,391 ft^3 in Table F.3. 2,975 ft^3 catalyst volume confirmed by NEC with Refinery 5 and via review of SCR data provided by Refinery 5 to SCAQMD.
2. Design value reported as 155 ppmv @ 0% O_2. Value presented in table is corrected to 3% O_2.

3. Measured outlet NOx value of <2 ppmv corresponds to operation of unit with inlet NOx in the range indicated. Removal efficiency based on range of actual operation.
4. Staff reports space velocity value of 2,974/hr in table F.3.
5. Confidential data provided by SCAQMD staff is insufficient to calculate the catalyst volume for this unit without making the following assumption on the depth of a catalyst module which we assume to be 45". Staff used ½ of this value in Table F.3 corresponding to catalyst bed depth (catalyst element height) of 22.5". Recommend staff confirm catalyst volume with Refinery 6.
6. Confidential data on unit design and performance, provided by SCAQMD staff, used to calculate inlet volumetric flow and space velocity. Values differ from staff's entries in Table F.3.

In their review, staff is suggesting that NEC's typical SCR is overdesigned and as a result overpriced. Staff's comparisons suggest an overdesign factor of as much as 284%. We do not agree with this assessment. As can be seen in Table 1, NEC's typical SCR should be able to achieve 97% NOx reduction by virtue of the addition of catalyst at higher gas velocities than the SCR operating at Refinery 1. The typical SCR design provides an approximate 21% margin in space velocity over the Refinery 1 SCR design primarily due to the addition of a third catalyst bed. The addition of a third bed has inherent performance advantages in that it provides for partial redistribution of unreacted NH_3 and NOx versus further cross sectional area additions. If it is determined that the incremental cost of specially fabricated catalyst modules (shorter depth) is low, some further optimization may be possible to reduce SCR cost. It is worth noting that the ~21% catalyst margin will have a 12% overall TIC and PWV cost impact.

Basis of the: ***"mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs"***

The following paragraphs provide background for NEC's use of a 35% conditioning factor for vendor equipment quotes at early stages of projects. These concepts were discussed with SCAQMD staff during reviews of our report and in subsequent follow-up phone conversations and e-mails. Due to the extensive discussion around this topic we are mystified by staff's characterization of this "bid conditioning factor" as, and here I paraphrase, 'an undefined and therefore invalid cost increase'.

Obtaining budgetary quotations from vendors for their equipment is part of the process of developing cost estimates for any project. At the early stages of projects, or when general information is sought, vendors are not provided comprehensive design basis information and therefore do not have a complete picture of the operating envelope for their proposed equipment. In these instances, some vendors will use costs from recent projects and "factor" them to the provided process conditions, other vendors may develop estimates based on equipment designed specifically to meet the provided process conditions. In either eventuality, the vendor is providing a quality estimate with reasonable accuracy (about +/- 10%) for the specified process conditions, without providing a performance guarantee and without review of the specific codes and standards applicable to refinery installations.

As project definition improves the process basis becomes fixed, equipment sizes become more reliable, performance guarantees are finalized, and vendor quote accuracy improves. Industry experience shows that at the early stages of a project, basis uncertainty alone, necessitates the addition of a 15 – 25% conditioning factor to a vendor's budget quote, in addition to other bid conditioning factors, to account for the difference seen between early equipment bids and final, full definition, performance guaranteed, equipment bids based on a definitive project basis.

Refineries are built to a more rigorous set of standards than typical air pollution control equipment which makes projects in the refining sector slightly more expensive than typical industrial projects. Standards which will have an impact on either the SCR design, the structural support design, location of equipment, internal and external maintenance access, etc., are likely to increase Direct SCR M&L costs. At this stage of project definition a factor of 10% is added to a vendor's equipment bid to account for the cost of meeting local plant standards.

The 1.35 "mark-up" or bid conditioning factor used in NEC's cost work-up for all SCR projects (FCCU, Heaters/Boilers, etc.) is not an arbitrary factor used to inflate costs, as implied in Appendix F, but is actually the low end of a time tested and proven means to determine the actual cost of a piece of equipment after full project definition is complete, including application of local industry standards to the design of the equipment, performance guarantees are offered and firm pricing for equipment components is provided by the vendor.

Basis for: ***"Adding another 75% increase in labor to the costs of the manufacturer's SCR."***

Another cost factor discussed with SCAQMD staff, and apparently dismissed as a simple adder to make costs appear high, is the cost of actually installing the equipment supplied by the SCR vendor in the plant. The vendor does not do construction and does not quote the cost of field assembly in their quote which only covers fabrication and supply of the equipment, in this case the SCR catalyst, support frames, ammonia injection grid and the carbon steel box.

The labor cost factor used in NEC's development of project costs is applied to the SCR vendor's factored estimate to account for the labor required to install the manufacturer's equipment at the site, transportation, taxes, tie-ins, insulation, access, structural steel, etc. Installation labor for equipment can range from a low of about 30% of the equipment cost to as much as 200% of direct equipment cost depending on the complexity of the equipment, the material it is made of and other equipment specific factors. In general, low cost equipment manufactured of low cost materials have higher installation percentages than highly complex equipment made of high cost materials. As a reference point, "Applied Cost Engineering", Clark F. D. and Lorenzoni A. B.; Marcel Decker Inc., 1978, uses a factor of 2.2 times direct material costs to estimate the direct M&L cost of a fired heater installation, a factor of 3.0 times direct material costs to estimate the direct M&L cost of a pump installation and a factor of 2.9 to estimate the direct M&L cost of a distillation tower. Due to the simplicity of the SCR equipment and its use of low cost materials we have used an installation labor cost factor of 0.75 (75%) to account for physical installation of the SCR, structural steel, fit-up of ducting, connection of piping, foundations, excavation, instrumentation, insulation, equipment storage, etc. This factor does not account for any costs associated with: demolition of existing equipment, modification of existing equipment, labor inefficiencies attributed to working in an operating plant, relocation and/or modification to underground utilities, piping, piping supports, ammonia storage facilities, control system additions, instrumentation wiring, conduit, power wiring, area paving, area lighting, area utilities, safety facilities, sootblowers, etc.. The cost of these items is rolled up into the overall TIC factor applied to escalate SCR M&L costs to a total project cost.

TIC Factor

SCAQMD staff disputes NEC's use of a TIC factor of 4.5 to convert direct M&L costs for the SCR into TIC for the SCR PROJECT. This factor is a reasonable estimate for project items not specifically identified in the direct M&L costs (indirect costs, engineering and owner's costs, labor productivity, ancillary equipment and systems, revamp items, duct work, area paving, lighting, utilities, safety systems, control system connections and programming, instrumentation, sootblowers, etc.) As a point of reference, the TIC factor used by NEC, in this analysis, is 90% of the average TIC factor of 4.9 used to estimate SOx control costs in NEC's SOx RECLAIM report.

NEC Estimated FCCU Feed Rates from
Flue Gas Rate Data Provided by SCAQMD
Correction of NEC PWVs Required

SCAQMD staff is correct in pointing out that NEC used incorrect design capacities in developing the FCCU SCR costs shown in section 1.2 of NEC's non-confidential report (14-045-4, November 26, 2014). NEC back calculated expected FCCU rates from flue gas flow rate data provided by AQMD staff to obtain estimated FCCU sizes. The following table presents a revision to the report table based on corrected FCCU sizes as indicated by district staff. Also included in the table is an update to the cost of a Grass Roots SCR for Refinery 6 based on a comparison of flue gas rates to the SCR versus the typical (base case) SCR. Revised NEC estimates provided in Table 2 do not include any reduction to NEC's original cost estimate model.

Table 2 (Restatement of Table F.2)
Estimates of PWV Correcting NEC Values for FCCU Feed Rates

Facility	FCCU Feed, kBPD	AQMD's Estimate, $M	Revised NEC Estimate, $M	Ratio: NEC/AQMD
5	71	33	43(2)	1.3
6	90	57	62(1)(2)	1.09
7	55	27	37	1.37
4	34/36(3)	16	28	1.75
9	55	19	37	1.95
Total		152	207	1.36

Notes:

1. The PWV shown includes the impact of additional flue gas from a CO boiler but does not include the incremental flue gas from another source which is fed to the existing SCR.
2. Costs shown are for grass roots (new) SCR additions to existing FCCUs. Existing units may be modified to reduce compliance costs below those indicated.
3. Staff report throughput is 34 kBPD. Published unit capacity is 36 kBPD.

**Staff Evaluation of NEC PWVs vs. Refinery 1 SCR Costs
Does Not Factor In Project Scope Differences**

Staff provided a review of NEC's cost estimates based on a comparison to the cost provided for Refinery 1's SCR to demonstrate that NEC's estimating method is overly conservative. In this comparison staff claims that NEC's cost tool over predicts the cost of this installation by $11M (27%). The difficulty in comparing a specific project to a generalized curve is that the project has a specific scope which in most cases is different than the assumed scope of the "typical" project. This is the case for the SCR installation at Refinery 1 which, according to Refinery 1 personnel, did not include the cost for waste heat boiler modifications. Subtracting this component from the TIC for a typical FCCU SCR installation and recalculating PWV yields a cost of $45.45M which is 10.8% higher than staff's cost work-up on this project of $41M, not the 26% difference indicated in Appendix F. Staff had the WHB cost information NEC used in our estimates, we do not understand why they did not make the PWV comparison on the same basis.

**Staff Evaluation of NEC PWVs vs. Refinery 9 SCR Costs
Misstates Vendor and NEC Information**

Staff also provided a review of NEC's cost estimates based on staff's assessment of differences between the data provided by an SCR vendor to staff and NEC for an installation at Refinery 9. In staff's evaluation of the data provided by the vendor they incorrectly calculate the total catalyst volume to be 3,100 ft^3 vs the actual vendor proposal which provided only 2,400 ft^3. Staff also incorrectly calculates NEC's estimated catalyst volume at 12,697 ft^3 vs an actual value of 4,600 ft^3 (1.92 x vendor proposal, see previous discussion on catalyst volumes and specification of a third bed).

**Comments on Staff's Determination of
PWVs for FCCU SCRs**

I would like to take the opportunity to provide a few comments on SCAQMD staff's determination of PWVs for FCCU SCRs.

1. In using the costs provided for Refinery 1's SCR staff is assuming that all district SCRs can be installed without any impact on upstream equipment and that installation of the SCR can be executed in an open, non congested area. Refinery 1's SCR was installed prior to the installation of a large ESP, which occurred around 2006. If the SCR was to be installed today, or at any time after installation of the large ESP, costs would be higher due to productivity debits associated with working in a congested area and quite possibly even higher due to the need to move or modify some equipment to make the installation possible. In the most extreme case the SCR and ducting may have to be field erected from small fabricated assemblies due to access constraints.

2. Staff used a 0.7 power factor to scale the costs for Refinery 1's SCR project to different sizes. Costs for FCCU regenerator flue gas systems scale more accurately when a figure of around 0.6 is used. The effect of using a larger scale factor is a greater reduction in project costs for all projects with the differences getting proportionately greater the further one gets from the base case unit size. In essence using the 0.7 factor instead of 0.6, in this particular evaluation, will decrease costs for all units and will disproportionately decrease the cost of smaller units.

3. In using vendor budget quotes for SCRs, staff needs to add erection labor to the vendor quote. There is no indication that this is done in staff's analysis.

4. Staff does not condition the vendor's quotes to account for operational conditions, including unit upsets, and other project unknowns which will have direct bearing on SCR design details, performance and costs. An allowance must also be made for the accuracy inherent in vendor's budget quotations, which does not appear anywhere.

5. The PWVs provided for Refinery 7 and Refinery 9 are $27M and $19M respectively. There is an apparent inconsistency in these numbers as the stated capacity for each of these units is 55 kBPD. Units of the same capacity should have PWVs close to one another not differing by 42%. Staff should check these numbers and ensure that the SCR project scope differences between these two units can explain the large difference in cost.

In the interest in getting our comments into your hands as soon as possible we will provide comments on Staff's review of our SCR estimates for other applications in the district in one or more separate letters.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc:

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C. A. Steves

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S. G. Haydel

AFPM – Washington, DC
A. Adams – AFPM
C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
K. Saffell - Valero
B. Williams - AFPM

Chevron El Segundo Refinery
J. Doyle
S. Worley
R. Spackman

ExxonMobil Torrence Refinery
S. Holm
P. Sheng

Paramount Refining Co.
K. Gleason
H. Chang

P66 LAR
K. Beruldsen
S. Micucci

Tesoro Carson / Wilmington
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September 4, 2015

Philip M. Fine, PhD
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
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Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for Fired Heaters & Boilers
Document No. 14-045-8

Dear Mr. Fine,

We have completed a review of the above captioned report's discussion of SCR applications to district Refinery Fired Heaters and Boilers and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve

NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on Heater SCR Project Costs

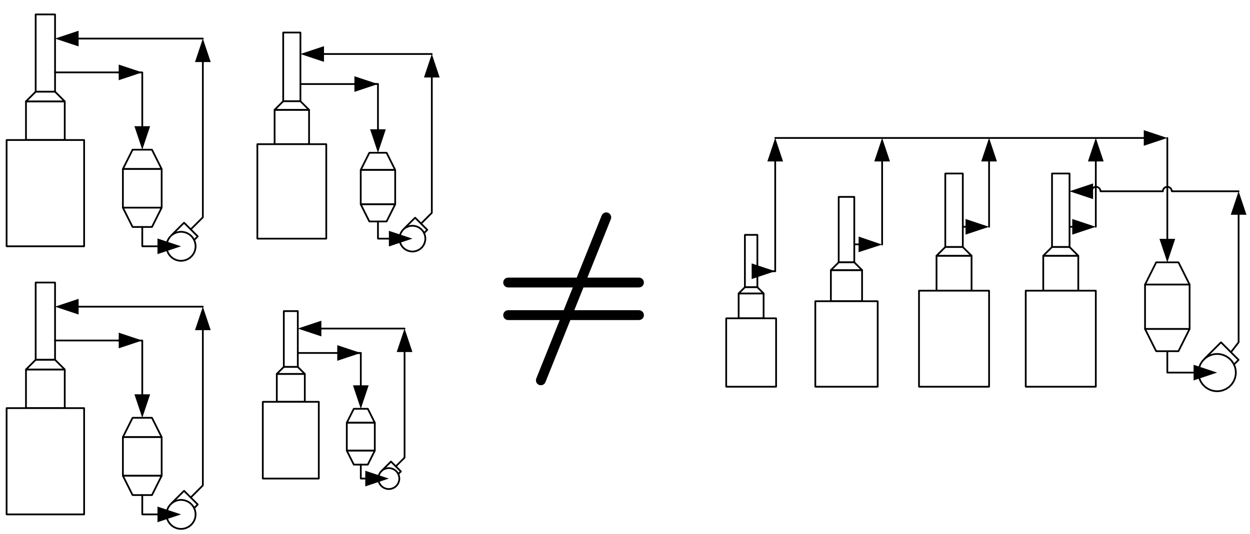
Appendix G to Staff's Draft Report presents a review of NEC's analysis of Heater and Boiler SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommendations did not include an assessment of the efficacy and cost of alternative NOx control technologies.
- NEC developed TIC estimates using a direct M&L multiplier of 4.5 vs staff's use of a TIC factor of 3.87.
- NEC used SCR catalyst and enclosure costs, obtained from SCR suppliers, for FCCU applications and used these costs as a basis for estimating the cost of heater and boiler SCRs.
- NEC recommends including space for four catalyst beds and designing for superficial gas velocities of 10 ft/sec.
- NEC included costs for new CEMS in their project cost estimates.
- NEC's costs estimates for smaller heaters and boilers are biased high by specification of ammonia systems which are too large for these small units.
- NEC's operating costs are biased high due to the cost of catalyst replacement which is higher if/when with higher installed catalyst volumes.
- NEC's estimates are skewed high because they are higher than staff's estimates which are conservative in the base case.
- NEC conditioned budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment.

- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: "additional labor".

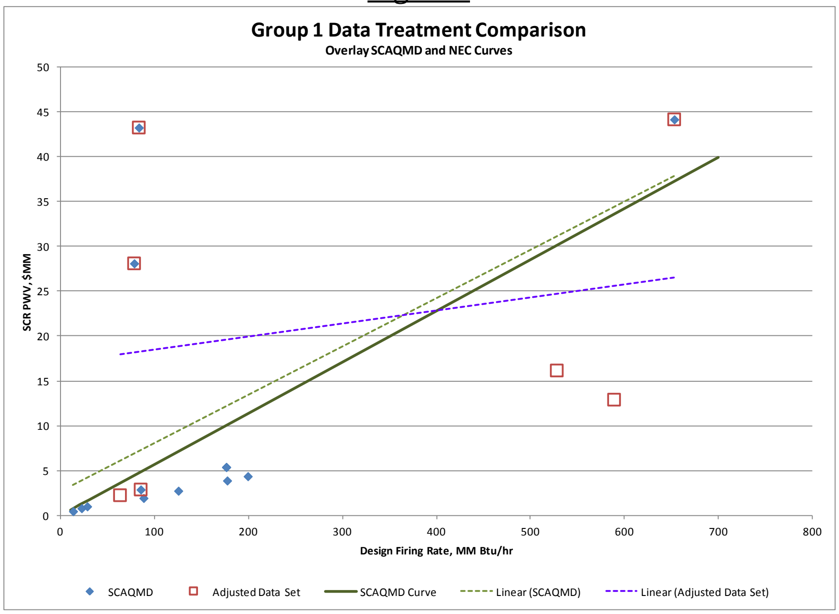
Before getting caught up in the minutia of Appendix G, I want to first present an overall picture of the PWV estimates developed by AQMD staff and those developed by NEC. The first thing we noticed in reviewing staff's use of refinery cost survey data, was that PWVs for SCR installations servicing multiple heaters were broken down and allocated to each heater based on design firing rate. This was done to obtain data points for SCR installation costs for individual heaters as a function of heater design firing rate. The problem with parsing the data in this manner is that it assumes that project costs for multiple heater installations and single heater installations are equivalent. They are not. Sharing an SCR between heaters is always lower cost than installing an SCR on each heater. We estimate that multiple heater SCR installations can cost as much as 30 to 70% of single heater installations with the savings coming from a reduction in SCR box steel and structural support, a reduction in the number of fans required for the installation, a reduction in foundations, ammonia distribution piping, controls, etc.

I believe that the following sketch provides a much better explanation of the difference between multiple and single heater SCR installations:



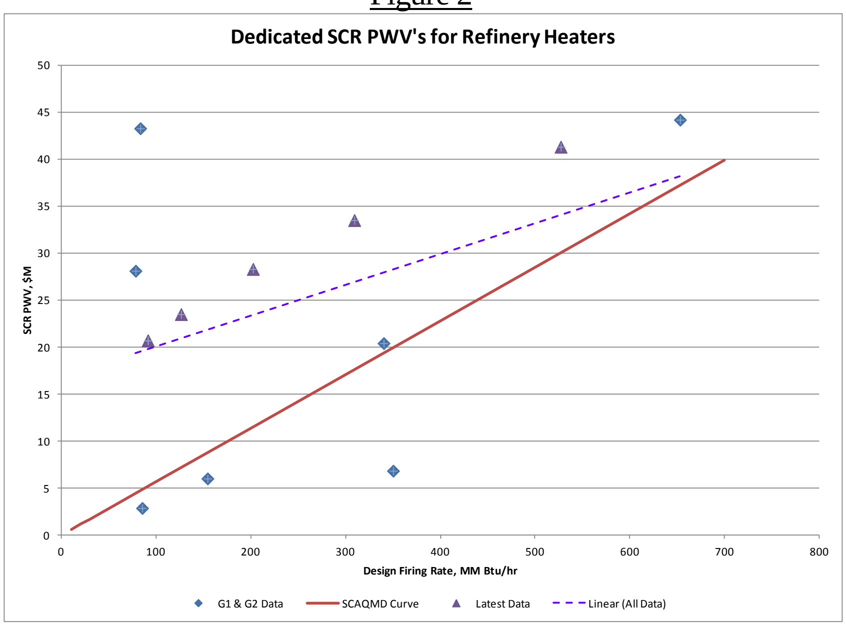
The following figures provide an illustration of the effect of staff's cost allocation assumption on the estimated PWVs of small heaters. Figure 1 presents two sets of survey cost data denoted as Group 1 data in the draft report. The data set named SCAQMD includes the parsed PWV data for three of the seven best performing SCRs in the district resulting in a total of fourteen data points. The data set named "Adjusted Data Set" combines the duties of the seven heaters which share SCRs into three data points yielding a total of seven data points. The revised data points represent SCR systems designed for a heater with a size equal to the combined firing rate of all the heaters sharing the SCR. Linear regressions of the parsed and non-parsed data are shown as dashed lines in the figure. The solid line is staff's PWV relationship. While the data is widely scattered and does not curve fit very well (R^2 = 0.3 for curve fit of parsed data and 0.05 for non-parsed data) the slopes of the two curves are very different and indicate that staff's correlation likely under predicts PWVs for heaters smaller than 400 MM Btu/hr; quite a different conclusion than that drawn in the draft report.

<u>Figure 1</u>



Norton Engineering understands that the number of survey project and operating cost data points on high performing SCR units is both limited and scattered and that additional information is needed and has been used by staff to generate more representative PWVs for refinery heaters. Figure 2 provides a comparison of staff's PWV correlation with available Group 1, Group 2 and additional SCR project cost estimate data provided to AQMD by a district refinery during NEC's review. All data are for dedicated SCR installations.

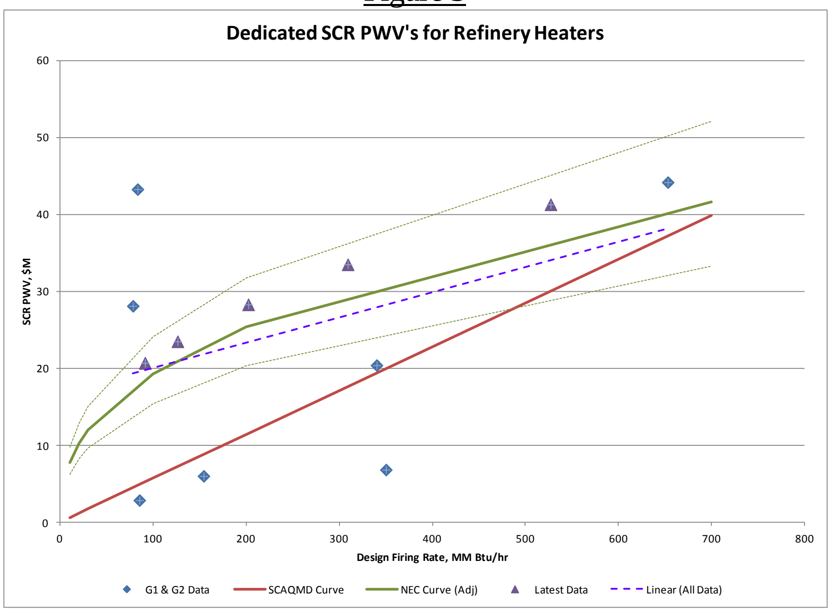
<u>Figure 2</u>



The purple dashed line in the figure represents a linear regression line for all the chart data. As with Figure 1, the large scatter in the data makes the correlation, any correlation, almost meaningless. The conclusion we can reliably draw from this chart is that staff's PWV correlation under predicted PWVs (based on actual and estimated TICs) in eight out of twelve instances, over predicted PWVs in one out of twelve instances and was accurate in three out of twelve instances. If staff's correlation was conservative we would expect that it would over predict PWVs more often than it under predicted PWVs. That is clearly not the case.

Figure 3 is a repeat of Figure 2 including NEC's proposed PWV correlation and the cost bands recommended for use in estimating complex and simple, single heater – single SCR PWVs.

Figure 3



NEC's proposed correlation provides PWV estimates for dedicated SCR projects which are more representative that staff's proposed correlation, matches up pretty well with the linear correlation of all data and, is not overly conservative. Six data points are higher cost than predicted by NEC's correlation, four are lower cost and two are predicted pretty accurately. When the complexity bands are used, the correlation under predicts in two of 12 cases, over predicts in four of twelve cases and is "accurate" in six of twelve cases.

For the specific case of smaller heaters (<100 MMBtu/hr heat release) NEC's correlation shows a very steep slope indicating that costs for small heater SCR installations rapidly increase with increasing heater size. This size sensitivity is expected as fixed project costs and non-size dependent project costs are normally a higher percentage of small projects than they are of larger projects. Staff's proposed correlation does not show this trend and therefore can be expected to significantly under predict PWVs for smaller heaters.

The following paragraphs address each of staff's comments and objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report. While the items covered in the following paragraphs may be open to interpretation, our previous analysis of available cost data indicates that any changes SCAQMD staff might want to make to NEC's "typical fired heater and boiler project basis" will likely necessitate changes to equipment definition, equipment cost or estimate cost factors to improve the cost correlation with Group 1, Group 2 and subsequent project cost data.

Scope of NEC's Review of AQMD Staff's
Preliminary Draft Report – September 23, 2014

This comment seems irrelevant to the current discussion as Staff's entire discussion on refinery heaters and boilers is focused on SCR installations as BARCT for the 2 vppm emission limit. We discussed this with staff during our work and staff agreed that any dilution of our effort to evaluate these alternative technologies would not be desirable.

Using FCC SCR Costs Increased Heater &
Boiler SCR Cost Estiamtes

Staff provided NEC with heater and boiler SCR cost data from vendors for review. In our discussions with SCR vendors we focused on the more severe FCC applications and obtained detailed information on SCR costs for these applications. Much less data was available from staff's contact with SCR vendors. Attempts were made to obtain clarifications from SCR vendors which were either not received or received after issuance of NEC's report. In reviewing the design and operation of the best heater in the district (1.6 vppm outlet NOx) we found that inlet gas velocities were similar to our recommendations for FCCU SCRs while catalyst volumes were significantly less. Using the FCCU SCR cost as a basis NEC estimated and added the cost of and ID fan, an ammonia storage tank, and a new CEMS for each SCR project. We then factored the cost as described previously to arrive at a total project cost. We then compared the result of this method to available data on past and planned projects, Group 1, Group 2 and recent refinery estimates, and found the accuracy of this method to be reasonable and more accurate than staff's PWV correlation. Considering the scatter in the data and the relative good accuracy of the methodology we did not go further in refining any underlying assumptions or our cost estimating technique.

NEC TIC Factor of 4.5 vs.
Staff TIC Factor of 3.87

Details of how NEC developed the factored estimates we used to generate TICs and ultimately PWVs for heater and boiler SCR installations have been described at length in our SOx RECLAIM cost review report (Non-Confidential Report No. SCAQMD 10-014-04 dated June 10, 2010). All of the factors used in this analysis are consistent with those used for our SOx RECLAIM assessment. Additional discussion is also available in our letter of August 10, 2015 commenting on AQMD staff's assessment of NEC's FCC SCR PWVs.

It appears that staff relied on SCR vendor cost data (Group 3 data) to generate SCR project costs for heaters and boilers without adjusting vendor costs for the budgetary nature of the estimates, the screening level of the process data provided to the vendor, the cost of equipment installation or the need for ancillary equipment such as ducting, fans and controls. All of these components are typically included in a cost estimate before the addition of TIC factors which cover, undefined equipment and systems, indirect project costs, engineering, project management, operator training, start-up spares, civil works and site preparation, project contingency, shipping and taxes. Staff's use of a TIC factor of 4.0 applied to the budget cost of the SCR provided by a vendor is not adequate to cover the cost of the entire SCR project.

Basis for SCR Catalyst Increase and Velocity Reductions vs Vendor Budget Quotes

The district has 7 SCRs installed on 14 fired heaters, achieving 1.6 to 3.5 ppmv NOx @ 3% O_2. The best performing unit treats flue gas from four heaters with a combined total design firing rate of 589 MM Btu/hr and is designed to treat flue gas to achieve 5 vppm NOx at this rate. Reported operation of this unit is 65% of design when achieving <2 vppm NOx emissions. Low firing rate operation decreases superficial and space velocities across/through the SCR versus design conditions (lower flue gas mass flows and lower flue gas temperatures vs design) lower velocities and space velocities translate into improved unit performance. In addition, lowering heater firing rates cools the heater firebox which also decreases inlet NOx levels to the SCR.

More important to the current discussion on SCR application to achieve 2 vppm emissions limits is the use of design data for this unit by staff, to extrapolate catalyst volumes and system costs for design of new units. Since the "base" unit is operated at 65% of design, any use of this data in an extrapolation to other applications needs to account for the lower than design operating conditions. It is not apparent from our review of staff's assessments if they have made this adjustment which will be a minimum 54% increase in the costs of the base unit.

NEC looked at the available operating data and the SCR manufacturer's information provided by staff for our assessment. We interviewed the SCR owners and made the assessment, based on information obtained during these interviews and our experience in developing oil processing, infrastructure and environmental control projects for over 20 years in the US and International refining industry, that estimating typical SCR sizes, based on the design conditions for the best SCR in the district, which isn't operating anywhere near its design condition would result in specifying/costing units which were too small. The question of catalyst volume then became one of how much additional catalyst might be needed to ensure long term reliable operation of an SCR. For refiners this translates into an SCR design which does not limit refinery or unit operation at any time between scheduled turnarounds.

Final determination of SCR catalyst volume for a typical refinery heater application requires making a flue gas throughput correction to the base case design, as note above, and making adjustment to catalyst volumes quoted by vendors where catalyst change out times are shorter than five to six years. To achieve the long run lengths required in refinery applications, refiners will increase catalyst volumes to offset declining catalyst performance. This is done in the design of every fixed catalyst bed system in the refinery. Based on the vendor information provided by AQMD staff a doubling of vendor catalyst volumes would be needed to ensure reliable operation in excess of five years. The minimum adjustment to achieve 2 vppm NOx and long unit operating life is therefore 3x (1/0.65 * 2) typical vendor specified or currently installed catalyst volumes.

NEC included a total of four catalyst beds for 2vppm NOx designs when three beds will likely prove adequate. Our inclusion of the fourth bed was to provide operating flexibility to ensure long term compliance while burning variable composition refinery fuel gas. This bed added 11 ft to the height of a typical SCR compared with a three bed unit. Elimination of this bed will reduce proposed SCR height by less than 20% and will not have any impact on the cross sectional area of the catalyst bed. Adjusting the SCR cost to reflect this change will necessitate a change in TIC estimating methodology to improve the correlation with Group 1, Group 2 and subsequent project cost data (Figure 3).

Cost of New CEMS vs Upgrade

NEC did not have any data on the status/condition of existing CEMS and therefore included the cost of a new CEMS, CEMS enclosure, stack platforms, access, etc. in the heater and boiler SCR project TIC estimates. A reduction in this cost will necessitate a change in estimating methodology to improve the correlation with Group 1, Group 2 and subsequent project cost data (Figure 3).

Specification of "Large" Ammonia Storage Tanks Biases Costs for Small Heaters High

A stand alone ammonia storage system will include a storage tank with sufficient volume to receive a full truck load of ammonia while operating with a heel sufficient to run the associated SCR for a defined, short, period of time. Local bulk ammonia suppliers suggest a minimum tank size of 11,000 gallons. NEC used this tank size as the basis for all district SCRs without increasing size for larger heaters which will receive ammonia deliveries more frequently.

NEC did not include the likely cost savings impact of centralized ammonia storage and distribution systems in our analysis. While on the surface it appears that significant savings can be gained from such systems, the need for long runs of small bore piping on existing pipe racks, through operating units, with frequent pipe supports (small bore piping cannot span typical pipe rack supports and needs multiple intermediate supports) and requiring significant scaffolding to be erected, makes ammonia distribution from centralized storage facilities nearly as costly as dedicated storage, and in some cases more expensive. For this reason, dedicated storage is a more reasonable option during early stages of project definition.

High Catalyst Replacement Costs Skewed NEC PWVs High

Staff is correct in their assessment that high catalyst volumes (FCCU SCR basis) in NEC's basis yielded high catalyst replacement costs and increased PWVs for heaters and boilers. A correction to annual operating costs should be made to correct this error. When this is done PWVs estimated by NEC's correlation will drop and will under predict Group 1, Group 2 and subsequent project cost data. An adjustment in NEC's TIC estimating method will be required to reestablish prediction accuracy for PWV (Figure 3).

NEC's Estimates are Higher Than Staff's "Conservative" PWVs

Staff has incorrectly used NEC's PWV correlation to demonstrate a reported 250+% difference in cost for a refinery SCR. Table G. 8 is recreated below with an additional column showing the correct use of NEC's correlation for PWV.

Table G. 8A – SCR Costs Estimated by Staff and NEC for Four Process Heaters Vented to a Common Stack (Shared SCR)

Heater	Rating MM Btu/hr	Staff's Approach Upperbound PWV	NEC's Approach PWV	Corrected NEC Approach PWV
D471	177	$11 M	$27 M	--
D472	125	$11 M	$23 M	--
D473	88	$5.5 M	$20 M	--
D3031	199	$11M	$28 M	--
Total	589	$38.5 M	$99 M	$43.2 M

As discussed previously in this letter we expect the SCR project cost for shared units to be less than what would be calculated for each individual unit. Costs should be more in line with the cost of an SCR for the total fired duty of the heaters feeding the SCR. In this case the difference between staff and NEC is 12% not 250+%.

Based on the data which staff purports to use to "calibrate" their conservative PWV correlation for fired heaters and boilers, staffs correlation is neither calibrated nor conservative. NEC has provided AQMD with a reasonable correlation for estimating the cost of SCR installations on refinery heaters and boilers as validated by the same data set staff is using. We agree that operating costs for heater and boiler SCRs should be reduced in the PWV calculation to correct the operating cost impact of over specification of catalyst volume. After making this correction (staff has the TIC correlation) we recommend staff use the resulting PWV correlation to estimate the cost of heater and boiler NOx control.

It is a shame that NEC and AQMD find themselves disagreeing on so many items in a public forum. I wish that we had discussions on more of the specifics of our review of AQMD's draft report and our recommendations for changes to the way cost estimates were prepared between November 2014 and July 2015. Perhaps we could have clarified and/or resolved some of these issues prior to AQMD staff developing the draft report and the recommendations which are based on the cost evaluations in question. It would have certainly made everyone's life a little easier.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc:

NEC – Montville, NJ
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J. A. Norton
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D. Vizzuso
S. Zhang, PhD
Z. Zhang

NEC – Swedesboro, NJ
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NEC – New Orleans, LA
S. G. Haydel

AFPM – Washington, DC
A. Adams – AFPM
C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
K. Saffell - Valero
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Chevron El Segundo Refinery
J. Doyle
S. Worley
R. Spackman

ExxonMobil Torrence Refinery
S. Holm
P. Sheng

Paramount Refining Co.
K. Gleason
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P66 LAR
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S. Micucci

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Valero LA Refinery
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M. Smith

WESPA
S. Gornick

VIA ELECTRONIC MAIL

August 21, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: NOx RECLAIM INDUSTRY COALITION COMMENTS ON CURRENT DISTRICT STAFF PROPOSED AMENDMENTS TO REGULATION XX DATED JULY 21, 2015

Dear Dr. Fine:

The following trade associations in representing their members have joined together to form the NOx RECLAIM Industry Coalition ("the Coalition"):

California Asphalt Pavement Association (CalAPA)
California Construction & Industrial Materials Association (CalCIMA)
California Council for Environmental and Economic Balance (CCEEB)
California Manufacturers and Technology Association (CMTA)
California Metals Coalition (CMC)
California Small Business Alliance (CSBA)
Regulatory Flexibility Group (RFG)
Southern California Air Quality Alliance (SCAQA)

Western States Petroleum Association (WSPA)
Los Angeles Business Federation (BizFed)

Members of the Coalition have been actively following the District staff proposals regarding a NOx RECLAIM shave ostensibly being proposed to reflect advances in Best Available Retrofit Control Technology ("BARCT") between 2005 (the last NOx RECLAIM shave) and today. Following the release of the preliminary draft staff report and the proposed amendments to Regulation XX on July 22, 2015, the Coalition members believed it necessary to make these written comments and ensure that staff is fully aware of our concerns and that those concerns are included in the administrative record.

PROPOSED SHAVE AMOUNTS AND TIMING

District staff has proposed the following shave implementation schedule:

Year	Shave amount (tons/day)
2016	4
2017	0
2018	2
2019	2
2020	2
2021	2
2022	2

A shave of 4 tons per day in 2016 does not allow any time whatsoever for facilities to develop and implement emission reduction measures. Indeed, it could potentially put many of the RECLAIM facilities at risk of non-compliance with their respective RECLAIM caps, resulting in deductions from their 2017 RTC allocations. Moreover, the District expects that the bulk of the BARCT emission reductions will be made at the refineries[1]. At NOx RECLAIM Working Group meetings, staff has conceded that those reductions will not be achievable for several years into the future, at the earliest, due to the complexity of the permitting and siting issues and the magnitude of the construction activities necessary to achieve the BARCT levels projected by District staff. Thus, it is illogical to require the largest shave amount to occur at the earliest possible date.

The Coalition understands that the District has committed itself in the currently operative AQMP to implement a certain level of NOx reductions from the RECLAIM universe as a contingency measure if the District failed to attain the 24 hour PM2.5 NAAQS by the end of 2014. However, there is no commitment in the AQMP to make a 4-ton per day shave in 2016. Indeed, the AQMP contemplated a 2-3 ton per day reduction in Phase I and another 1-2 tons per day in Phase II. (Preliminary Draft Staff Report, page 2). Moreover, the AQMP specifically considered <u>and rejected</u> whether such an early action shave should remove all "excess" RTCs (i.e., the entire

[1] SCAQMD PDSR, Proposed Amendments to NOx RECLAIM, July 21, 2015, page 18.

"gap"). Rather, it was determined that only a 2-ton per day reduction was appropriate. Accordingly, the Coalition believes that the shave amount for the period 2016-2017 should be no more than 2 tons per day, and that there is no reason that all two tons have to be shaved in 2016. In fact, given that 2016 is almost upon us, and certainly will be by the time the amendments are adopted, it may be appropriate not to make any adjustments to 2016 allocations. Finally, we believe that the public record supports the view that the Governing Board approved the AQMP and CMB-01 with the understanding that if the 24 hour PM2.5 NAAQS was not attained, no more than 2 tons per day would be removed and that additional NOx reductions from RECLAIM would not be needed as a contingency measure to meet this purpose.

With respect to the total amount of the shave, the Coalition continues to believe that shaving a total of 14 tons per day of RTCs from the RECLAIM market in order to achieve the 8.79 tons per day reductions the District seeks to obtain as a BARCT adjustment is neither necessary nor justified.[2] We understand that District staff believes that the BARCT reductions won't occur unless almost the entire "gap" between RTC holdings and reported NOx emissions has been eliminated. History has shown that the staff is incorrect on this assessment. As shaves have been implemented, emissions have gone down to reflect past BARCT adjustments, even as the "gap" has remained relatively stable at 5-9 tons per day. A shave of 14 tons per day is excessive and risks destroying the RECLAIM market.

Finally, when implementing the shave, the amounts in the early years should be smaller and larger increments should be reserved for later years, to allow the BARCT installations to be implemented.

COST EFFECTIVENESS

The Coalition continues to believe that a 25 year useful life assumption (used consistently for all equipment in this proposed rulemaking) is not appropriate for all equipment. Additionally, we believe that the District staff has underestimated the cost for several equipment categories. District staff minimizes control costs by using a cost-effectiveness calculation[3] that is not used by the California Air Resources Board and most other major California air districts. Additionally, the use of a $50,000 per ton figure as the cost threshold is more than twice the $22,500 per ton threshold applied to command-and-control regulated sources. This is inconsistent with Health and Safety Code Section 39616 which requires that the RECLAIM program "not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment."

We also note that Norton Engineering (the third party independent contractor retained by the District to review and assess the District staff's cost effectiveness determinations) has raised

[2] The Coalition does not believe that the 8.79 tons per day figure is necessarily the correct number. We continue to take issue with the SCAQMD staff's cost-effectiveness calculations for a number of source categories and understand that Norton Engineering, the SCAQMD's third party BARCT evaluator, continues to have issues with the staff analysis as well. This will be discussed separately in this letter.

[3] The use by SCAQMD of the discounted cash flow (DCF) method as well as generous assumptions regarding useful life and interest rates result in cost effectiveness figures that show lower costs per ton of emissions reduced than other, more accepted, calculation methods.

questions regarding the District staff's cost effectiveness determinations and its dismissal of Norton Engineering's analyses when those analyses showed higher costs than the District staff's evaluation showed[4].

NEED FOR THE "GAP"

Our analysis has shown that even if the District staff concluded that NO BARCT improvements had been made between 2005 and today, the staff's methodology would result in 6 tons per day of NOx RTCs being removed from the program. RTCs being removed under the District's methodology would include those needed for:

- NSR Holding Requirements
- Electric Grid Reliability and Implementation of AQMP Attainment Strategies (i.e., large scale electrification to replace current combustion processes)
- Post-2023 Growth
- Investor Holdings
- Shutdowns
- ERC Conversions

Additionally, there are significant questions regarding whether the District staff's proposed 10% compliance margin is sufficient. A 10% compliance margin will likely be insufficient to assure sufficient liquidity to maintain a functioning market in light of the removal of the above listed RTCs from the program.

We are also concerned that RTCs reflecting investor holdings and ERC conversions are proposed to be "taken" by the District as a result of the District's BARCT shave methodology with no analysis of the financial impact or the costs associated with such a taking[5].

We understand that District staff is working with electric power generators to address the NSR holding requirement issue[6]. While the Coalition agrees that something must be done to address the NSR holding requirement, the current proposal is a complicated attempt to address a problem that only arises because the District staff is trying to eliminate the "gap" altogether. One of the complicating factors associated with the current staff proposal is that it would allow the Adjustment Account to be utilized both to address the NSR holding requirement and to cover actual emissions from power plants under certain contingencies. This brings into question whether or not the Adjustment Account will be adequately funded to cover potential demand. Furthermore, the proposal is fraught with risk because it needs EPA approval, which is not assured. The Coalition believes that the size of the shave should not include RTCs that are required to be held for NSR holding purposes. However, if the District insists on going forward with its proposal, no amounts of RTCs held by electric power generators to satisfy their NSR holding requirements should be shaved unless and until EPA approval is finalized.

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[4] NEC-SCAQMD letter dated August 10, 2015.
[5] SCAQMD PDSR, Proposed Amendments to NOx RECLAIM, July 21, 2015, Chapter 4.
[6] SCAQMD Staff stated meetings were being held with power-related stakeholders at the June 4 and July 9, 2015 working group meetings.

In summary, the District's proposed shave goes way beyond what is required to comply with the Health and Safety Code requirements with respect to a BARCT adjustment and runs the risk of repeating the program "meltdown" of 2000-2001 during the power crisis when insufficient RTCs were available.

ENERGY EFFICIENCY PROJECTS

As we stated in our June 19, 2015 comment letter, the Coalition strongly opposes any effort to further reduce RTC allocations due to "energy efficiency projects" that have or would reduce NOx emissions. Any reduction in NOx emissions not strictly required by BARCT should be encouraged and the benefits of making those reductions retained by the facility operator making them. For the District to consider taking away RTCs due to reductions in emissions occurring from efforts to improve energy efficiency would be a true manifestation of "no good deed goes unpunished."

CONCLUSION

We look forward to continuing to work with the District staff to develop a RECLAIM shave that represents a true BARCT adjustment while not endangering the life of the RECLAIM program. RECLAIM has been extremely successful in reducing NOx emissions from stationary sources while providing them the flexibility to make reductions in the most cost effective manner. We are very concerned that the severe reductions in RTCs currently being proposed by District staff go beyond adjusting for new BARCT and will result in facilities being subjected to the same RTC shortages that plagued the program in 2000-2001.

Respectfully,

Curtis L. Coleman

Curtis L. Coleman
Executive Director, Southern California Air Quality Alliance
On behalf of the NOx RECLAIM Industry Coalition

cc: Dr. Barry Wallerstein, SCAQMD
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August 20, 2015

Mr. Joe Cassmassi
Planning & Rules Director
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Proposed Amendments to Regulation XX, NOx RECLAIM

Dear Mr. Cassmassi:

We are writing on behalf of Southwest Generation Operating Company, LLC ("SWG") and its subsidiary Harbor Cogeneration Company, LLC ("HCC"), which owns a power plant located at the Port of Long Beach at 505 Pier B Street, Wilmington, California (Harbor Cogeneration Plant). The plant is listed as one of the top 90 percent of RTC holders that would be subject to a 47% "shave" in NOx RECLAIM Trading Credit ("RTC") holdings under the proposed amendments to South Coast Air Quality Management District (the "District") Regulation XX released by staff on July 20-22, 2015.

Basis for HCC Comments

The stated purpose of the proposed amendments to Regulation XX is to reduce NOx emissions from the universe of RECLAIM facilities by 2022 in line with current best available retrofit control technology (BARCT). The District staff has decided that the best way to achieve this goal is by reducing the holdings of the largest RECLAIM NOx holders in the basin. This includes the Harbor Cogeneration Plant and over 50 other power plants, refiners, industrial facilities and investors.

As HCC has discussed with District staff, its primary concern and the basis for submitting this comment letter is the District's proposal that the baseline date from which the "shave" will be taken be retroactive to RTC holdings as of March 20, 2015. The first time HCC was made aware that staff was proposing the March 20, 2015 baseline date was just prior to the public workshop on July 22, 2015. We understand the desire to establish a baseline to prevent manipulation through multi-step disposition and re-acquisition strategies. However, the current staff proposal to establish a retroactive baseline date without prior advance notice constitutes an unprecedented *ex post facto* action that unfairly disadvantages entities that have made good faith trades subsequent to the proposed baseline date.

Relevant Rule Language

In its rollout of the proposed amendments to Regulation XX, the District issued proposed revisions to Rules 2002 and 2005 on July 20, 2015, followed by proposed revisions to Rules 2011 and 2012 on July 21, 2015. The primary amendments are in Proposed Amended Rule (PAR) 2002. In paragraph (f), Annual Allocations for NOx and SOx and Adjustments to RTC Holdings, the proposed amendments to subparagraph (f)(1)(C) would apply to the Harbor Cogeneration Plant. The relevant proposed amended text of subparagraph (f)(1)(C) states:

> (C) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of *March 20, 2015* by the following adjustment factors for the relevant compliance year to each of the Facility Permit Holder listed in Table 8 to obtain tradable/usable and non-tradable/non-usable holdings: . . . (emphasis added)

We understand the need to set a baseline date in order to establish the inventory and identify potentially affected sources. However, choosing a retroactive baseline date without prior advance notice of the proposed date would be an *ex post facto* action that unfairly disadvantages entities, like HCC, that made good faith economic decisions in reliance on the rules in place at the time.

An *ex post facto* law or regulation is one that retroactively changes the legal consequences or status of actions that were committed, or relationships that existed, before the enactment of the law or regulation. Article I, Sec. 9 of the California Constitution prohibits the passage of *ex post facto* laws. Furthermore, in In re Lomax, 66 Cal. App. 4th 639, 643 (1st Dist. 1998) (citing *People v. Armitage*, 194 Cal. App. 3d 405, 414 (1987); *Flemming v. Oregon Bd. of Parole*, 998 F.2d 721, 726 (9th Cir. 1993), the court held that "Regulations have the force and effect of law and thus are subject to ex post facto prohibitions" of the state constitution. It is therefore unambiguous that the Constitutional prohibition on *ex post facto* laws applies to agency regulations, such as those of the District. The current proposal runs afoul of that prohibition by retroactively changing the legal consequences and status of trades that were made in good faith and without advance notice of the proposed March 20, 2015 baseline date.

Impact on Facility Planning and Engineering

The District's proposed retroactive baseline date of March 20, 2015 frustrates plans that HCC, and perhaps others, have developed and begun to implement to achieve early emission reductions, thereby undermining the purpose of the RECLAIM program and the proposed amendments. HCC's planning window for engineering upgrades and plant performance improvements is a multi-year exercise. In order to accomplish their business goals, they implemented trades of their NOx RTC holdings this year that were completed after March 20,

2015. These trades were made to fund planned plant upgrades, including emission reduction strategies and possible plant expansions. This strategy is completely consistent with the market concept of the RECLAIM program. If the District were to retroactively reduce HCC's NOx RTC holdings, it would also retroactively alter the premises upon which they based their decisions to improve the plant during 2016 to 2020 such that those decisions may not make financial sense.

We are aware that other facilities in the basin have sold RECLAIM NOx perpetuity streams after the March 20, 2015 date. Presumably, the sales were used to finance upgrades to their facilities which would reduce emissions in the future (the fundamental purpose of this rule). The way PAR 2002 currently stands, like HCC, these entities would be penalized for their early actions to become more efficient and less polluting. The examples provided below illustrate some of the adverse consequences associated with the District's proposed action.

Example 1: A non-refining facility that held 100,000 pounds of NOx perpetuity RTCs on March 19, 2015 would be subject to a 47% shave. If this entity sold 50,000 pounds of NOx RTCs on March 25, 2015 to finance an upcoming project to reduce emissions, it would still be shaved 47,000 pounds based on its holdings of 100,000 pounds as of March 20, 2015. This would leave that facility with an allocation of only 3,000 pounds in 2022, far less than the facility originally planned. In this example the facility expected to reduce its emissions by half, finance a project with the proceeds from the sale of their future excess credits, and retain an allocation of emissions for future use. This example describes an action that should be applauded, rather than penalized, by the District because the facility is cutting its emissions.

Example 2: A facility may have sold all of its RTC holdings after the proposed baseline date, but before the shave date. For example, a facility may have held 100,000 pounds of NOx perpetuity RTCs on March 19, 2015 and sold all RTCs on March 25, 2015. The entity would be shaved 47,000 pounds of RTCs, but it has no remaining RTCs in its account. How would the District implement the shave? Would the District follow the RTCs and apply the shave to the purchaser, or would the facility "owe" 47,000 pounds of RTCs?

These are just a couple of examples of the potential consequences of the District's proposed action. We would expect the trading, selling and buying examples to be as numerous as the varied operations of the affected sources.

Baseline Date for RTC Holdings Should Be Date of Amendment

We urge the District to work with the affected sources to establish a baseline date that is not earlier than the date of adoption of the rule amendments. This would provide clarity to businesses making financial and operational decisions, and stability to the District in establishing a credible inventory. In no case should the effective date to determine baseline RTC holdings be earlier than the effective date of amendment.

LATHAM&WATKINS LLP

We appreciate the opportunity to submit these comments and look forward to working with the District to refine and implement the proposed amended rules. If you have any questions please contact me or Bob Louallen, HCC's Senior Environmental Compliance Engineer at (702) 239-3712.

Kind regards,

Michael Carroll
of Latham & Watkins LLP

cc: Bob Louallen

August 21, 2015

Kevin Orellana, AQ Specialist
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Subject: Comments on Proposed NOx RECLAIM Amendments

Dear Mr. Orellana and Ms. Pham:

Please find herein comments on the draft RECLAIM Rule language dated July 22, 2015.

NEW EMISSION FACTORS FOR RULE 219 EXEMPT EQUIPMENT

We support the District's August 19th proposal for new provisions in Rule 2012 Chapter 4 to allow equipment certified by either U.S. EPA, CARB, or SCAQMD to use an emission factor other than the default factor of 130 lb/mmscf to report NOx emissions.

Currently, when a RECLAIM facility installs an SCAQMD Rule 1146.2 certified hot water heater, they are directed by District staff to report their RECLAIM and Annual Emissions Report (AER) emissions using a default emission factor of 130 lbs NOx/MMscf natural gas (equivalent to ~102 ppm of NOx), even though the unit has been certified by the SCAQMD to be "less than or equal to 20 ppm of NOx emissions (at 3% O2, dry)…" per Rule 1146.2. The estimated emissions factor associated with 20 ppm is approximately 25 lbs/MMscf, which is less than the 2010 ending emission factor. Manufacturers may not sell heaters for use in the District unless it complies with Rule 1146.2. We support that the RECLAIM rules are proposed to be modified to allow accurate reporting of emissions for R219 exempt equipment.

RULE 219 EXEMPT EQUIPMENT REPORTING

The District's August 19th proposal for certified Rule 219 exempt equipment indicates source tests may be required to verify lower emissions. We request that no source test shall be required for certified equipment. The SCAQMD specifies the emission certification process and accepts the documentation provided by the manufacturer as adequate to demonstrate compliance with the emission standards of Rule 1146.2. Certified heaters/boilers have been available on the market for years, tested by the manufacturers, low NOx combustion technology is achieving well under 30 - 55 ppmv, and the heat input ratings of Rule 219 equipment are small. Moreover, facilities may have multiple small boilers onsite, and given the unit cost to source test is approximately $3,000-$4,000, this presents an unnecessary cost burden on these facilities. We request that the SCAQMD forego the requirement to source test small boilers and accept the emission certifications as adequate to document NOx emission concentrations for use in the RECLAIM program.

RTU REPORTING

We do not see that the District is proposing any changes to the electronic reporting requirements for NOx Major Sources. The current requirements are specified in 2012 Appendix A, Chapter 7 – Remote Terminal Unit (RTU) Electronic Reporting. This section of the rule requires facilities to use dial-up modem technology to transmit a text string that must be very specifically formatted. The use of dial up modems as telecommunication devices is woefully outdated. It is becoming difficult even to find dial-up modem systems and components since their functionality has been replaced by better technology. Moreover, the very specific text file formatting is very challenging and error prone whenever text files must be written for transmittal to correct previously reported emissions. We have wasted hours of time working with this antiquated system which is still required by the regulation. We urgently request that the District update their electronic reporting system to allow more modern and easy to use technology.

CONCLUSION

Thank you for considering these comments. We would be glad to meet with you and the RECLAIM team to discuss these important issues. Should you have any questions or concerns, please contact me at (949) 248-8490 x511.

Sincerely,

Kathy Prokey

Kathy Prokey
Sr. Engineer
Yorke Engineering, LLC
(949) 248-8490 x225

cc: Judy Yorke, Yorke Engineering, LLC
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August 21, 2015

BY EMAIL AND U.S. MAIL

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Re: Comment Letter on NOx RECLAIM Shave Proposal; Cities of Burbank and Pasadena

Dear Dr. Fine:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting the following comments on your staff's draft proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), published on July 21, 2015. While the NOx shave proposal appears to include provisions that would mitigate some of its worst impacts on the Cities' well-controlled power plants, it still does not provide the needed certainty that adequate RECLAIM Trading Credits ("RTCs") will be available at a reasonable price to cover these plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies. We would like to suggest some improvements to the proposal that would provide the needed certainty and address other issues.

Both Cities operate their own power plants containing peaking units, and BWP also operates the Magnolia Power Plant ("MPP"), a baseload unit, on behalf of the Southern California Public Power Authority ("SCPPA"). Participants in MPP include Burbank, Pasadena, and four other municipalities. The Cities operate these power plants to serve their municipal customers. RTCs are required not only to cover anticipated annual emissions, but also to meet resource adequacy needs and prepare for utility-specific operating contingencies, such as grid reliability, increased cycling to support integration of renewables, and potential electrification of the transportation system. Unlike other industrial facilities operating under the RECLAIM program, the Cities' power plants are obligated to operate to serve load. If they are unable to serve load, there may be blackouts with serious adverse economic and other consequences.

The staff proposal would require a 47% reduction in the NOx RTC allocations for these power plants. The proposed reductions are so severe that insufficient RTCs would remain to cover Pasadena's and MPP's anticipated emissions, not to mention RTCs needed for resource adequacy and utility-specific operating contingencies.

As you know from our discussions during the Working Group process preceding the proposal, the Cities have requested that their power plants be excluded from the proposed NOx shave. This request is rooted in history and fairness. The Cities have already achieved the goals of the RECLAIM program, and more should not be asked of them.

The Cities have already reduced NOx emissions as much as feasible with the installation of Best Available Control Retrofit Technology ("BARCT") at their existing units, at a cost of over $28 million. In fact, these reductions were achieved over ten years ago pursuant to a command-and-control rule, Rule 2009. These reductions were required in the wake of the energy crisis of 2001, which led to an increase in power plant operation for which adequate RTCs were not available. BWP also has installed Best Available Control Technology ("BACT") at its Lake 1 unit and at MPP, and PWP has under construction a boiler replacement project that also will have BACT installed. The Cities cannot make any further cost-effective NOx emissions reductions. When and if the shave results in a shortage of RTCs to cover operating needs, the Cities would not have the option of installing more control equipment. Instead, all they could do is purchase additional RTCs, if available, or fail to meet load.

Moreover, the Cities are ahead of schedule in meeting the state's requirement that all electricity retailers serve at least 33% of their load with renewable energy no later than 2020. Burbank is already at 34% renewables, and Pasadena is at 28% renewables with a goal of reaching 40% by 2020.

While the Cities therefore believe they should not be subject to the proposed NOx shave, they acknowledge that with appropriate safeguards, the potential adverse impacts of the proposed shave on the Cities' power plants could be substantially avoided. It appears that the staff proposal addresses one important adverse impact: the requirement that MPP hold enough NOx RTCs to cover its maximum rated capacity at the beginning of each compliance year ("NSR holding requirement"), in the face of a 47% reduction in its NOx allocations. The proposal would apparently relieve MPP and other "new," post-1993 facilities from that requirement by providing for an "Adjustment Account" that will meet this requirement on a programmatic basis [see Proposed Amended Rule ("PAR") 2002(f)(4)]. But the proposal only partly addresses the other major potential adverse impact: the prospect that adequate NOx RTCs will not be available at a reasonable price to cover these power plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies.

In the remainder of this letter, we will address these potential adverse impacts, and other issues as well.

1. Power Plants Need Quicker Access to Non-tradable/Non-usable NOx RTCs If Needed to Cover Annual Emissions

The staff proposal provides for a non-tradable/non-usable adjustment factor to be reflected in the permit for each facility subject to the 47% shave, including power plants, topping out at 0.335 in 2022 [PAR 2002(f)(1)(C)]. As we understand the proposal, it means that up to a 0.335 fraction of each facility's current allocation of RTCs would be made usable and tradable, and therefore available to cover annual emissions, in the event that the Executive Officer determines that the 12-month rolling average price of NOx RTCs exceeds $15,000 per ton (or $7.50 per pound) and after the Governing Board concurs in that determination [PAR 2002(f)(1)(F)]. No fee would be charged for these additional RTCs.

Based on the experience of power plants during the energy crisis of 2000-2001, this cumbersome, two-step process for releasing these RTCs to cover annual emissions appears to be too slow to avoid skyrocketing spot prices or an outright shortage of RTCs for power plants to either cover annual emissions or demonstrate resource adequacy. We understand that the Los Angeles Department of Water and Power will be presenting a more detailed description of how the two-step process for releasing RTCs during the energy crisis of 2000-2001 did not avoid high prices and shortages of RTCs at that time.

The Cities therefore suggest that a provision be added allowing power plants to request that some or all of this pool of non-tradable, non-usable RTCs be converted to usable but non-tradable RTCs, in exchange for a fee of $7.50 per pound. Once converted, the RTCs could be used to cover annual emissions or meet resource adequacy needs for the year in which the request is made, but they could not be traded. In addition, the power plant also would not be allowed to trade any of its own RTC allocation for the year in which the request to convert is made.

The fee serves two purposes. First, it gives power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound. As long as the spot price of RTCs remains below that level, power plants will not have an economic incentive to make a request to convert. Instead, they will rely on the RTC market to acquire additional needed RTCs. But if the spot price rises above $7.50 per pound, then they will have an incentive to make a request, if they deem it prudent to do so. Of course, power plants would be free to wait for the slower two-step process to unfold regarding the 12-month rolling average price, and obtain additional unrestricted RTCs without a fee, if they deem that to be the more prudent course.

The fee also serves the purpose of providing the District with funds to achieve additional NOx reductions from other sources, including mobile sources, for which cost-effective reductions cannot otherwise be obtained.

We understand that in response to questions posed at the Working Group meeting on August 19, District staff indicated it is their intention that the non-tradable, non-usable RTCs be removed from each facility's permit after 2022. If these RTCs are indeed removed from the permits, then the suggested provision discussed above would be of little or no use to the Cities, because it is precisely in the last year or two of the NOx shave, and in later years, that these RTCs are most likely to be needed. The Cities therefore also suggest that these non-tradable, non-usable RTCs, or some significant portion of them, remain on power plant permits after 2022.

Attachment 1 to this letter contains an example of rule language that might be used for a provision allowing the conversion of non-tradable, non-usable RTCs to usable but non-tradable status.

2. Power Plants Should Have Access to the "Adjustment Account" to Cover Annual Emissions

As mentioned earlier, the staff proposal contains an "Adjustment Account" enabling post-1993 power plants to meet the NSR holding requirement on a programmatic basis. We understand that staff estimates that 1 to 1 ½ tons of RTCs will be needed for this account [see Draft Staff Report at p. 33]. We suggest that the RTCs in this account also be made available to affected facilities to cover their annual emissions, in exchange for a fee of $7.50 per pound. There does not appear to be any impediment to allowing the RTCs involved to serve both purposes.

As in the case of a request to convert non-tradable, non-usable RTCs to usable but non-tradable RTCs, the fee serves the dual purpose of giving power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound, and also providing the District with funds to achieve additional NOx reductions from other sources for which cost-effective reductions cannot otherwise be obtained.

This use of the "Adjustment Account" could be viewed as an alternative to the suggested provision regarding the non-tradable, non-usable RTCs discussed above.

Attachment 2 to this letter contains an example of rule language that might be used to allow RTCs in the "Adjustment Account" to both meet the NSR holding requirement and be available to cover annual emissions.

3. Provisions Involving Delayed RATA Tests Due to Extenuating Circumstances

The Cities appreciate the staff proposal to allow postponement of a relative accuracy test audit ("RATA") when a major source is physically incapable of being operated. [PAR 2012, Appendix A, Attachment C, Section (B)(2)] Allowing postponement by rule provision would make it unnecessary for the Cities to incur the expense of petitioning the Hearing Board for a variance to allow postponement of the test. However, the Cities would like to suggest two changes to the conditions that apply to the postponement.

First, the due date for performing the RATA should be 30 days, rather than 14 days, from the re-firing of the major source. The additional time is needed in some circumstances to perform tests on the source to ensure reliable and safe operation. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

Second, the proposed requirement to disconnect and flange the fuel feed lines is unnecessary and costly. The proposed requirement is unnecessary because the fuel meters are required to be maintained, associated fuel records are required to be kept, and stack emissions are continuously monitored and recorded. So there are multiple sources of data to rely on to verify that the source is not operating. The proposed requirement is costly and time consuming because significant manpower and equipment would be needed to meet it. There also may be health and safety risks if asbestos-containing materials are encountered in the work. The Cities therefore suggest that this requirement be deleted. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

4. Other Comments and Questions

a. Provisions Involving the Non-tradable, Non-usable Adjustment Factor

i. The staff proposal should be clarified to provide that the 12-month rolling average RTC price that may trigger release of the non-tradable, non-usable RTCs is the "weighted" average. [PAR 2002(f)(1)(E)]

ii. The staff proposal speaks of determining the 12-month rolling average RTC price for all trades in the "current compliance year." It is not clear how this language would apply to a 12-month rolling average price when the 12 months in question straddle two adjacent compliance years. [PAR 2002(f)(1)(E)]

iii. In PAR 2002(f)(1)(F), the correct cross-reference appears to be to PAR 2002(f)(1)(E), not PAR 2002(f)(1)(F).

b. Provisions Involving the "Adjustment Account"

i. The staff proposal includes a provision allowing access to "Adjustment Account" RTCs for the purpose of compliance with annual emissions during a State of Emergency as declared by the Governor. [see PAR 2002(f)(5)] This provision raises several questions:

(1) How is the account to be funded for this purpose, and with what quantity of RTCs? As we indicated earlier, we understand that staff estimates that 1 to 1 ½

tons will be needed to meet the NSR holding requirement. Will additional amounts be added to fund the account to allow compliance with annual emissions?

(2) Why is access to RTCs limited to a State of Emergency declared by the Governor, as opposed to a State of Emergency declared by a local government official, such as a Mayor?

(3) We understand that in response to questions raised at the Working Group meeting on August 19, District staff indicated that RTCs in this account can be used both to meet the NSR holding requirement and to cover annual emissions. If our understanding is correct, then the rule language needs to be clarified.

(4) It may not be appropriate for the Executive Officer to have unfettered discretion to determine the amount and distribution of RTCs. By making these determinations, he would in effect decide which power plants generate electricity during a State of Emergency. Such decisions may be beyond his authority and expertise. It is important, moreover, that every power plant have access to the RTCs it needs to meet its operating requirements.

The Cities appreciate your consideration of these comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Jill Whynot, Assistant Deputy Executive Officer (via email)

ATTACHMENT 1

Proposed Amended Rule 2002(f)(1)(G) shall be added to read as follows:

"Notwithstanding the provisions of subparagraph (f)(1)(F), upon the request of a Power Producing Facility, all or a portion of the facility's non-tradable/non-usable NOx RTCs specified in subparagraph (f)(1)(C) shall be converted to usable but non-tradable NOx RTCs for the purpose of compliance with the facility's emissions, or to meet resource adequacy needs, for the year for which the request is made, for a user fee of $7.50 per pound (or $15,000 per ton) of NOx RTCs. Any facility making such a request shall not sell any of its NOx RTC allocation for the year for which the request is made."

Later subparagraphs will need to re-numbered to accommodate this new subparagraph.

ATTACHMENT 2

Proposed Amended Rule 2002(f)(6) shall be added to read as follows:

"Notwithstanding the provisions of subparagraph (f)(5), upon the request of a Power Producing Facility, the Executive Officer shall allow the facility access to Adjustment Account RTCs for the purpose of compliance with the facility's annual emissions, or to meet resource adequacy needs, for a user fee of \$7.50 per pound (or \$15,000 per ton) of NOx RTCs. These Adjustment Account RTCs are non-tradable. Any facility making such a request shall not sell any of its NOx RTC allocation for the year for which the request is made."

SCEC

August 26, 2015

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Subject: Backstop Measures for Municipal Utilities Operating Under RECLAIM SCEC 2564.2001

Dear Dr. Fine:

South Coast Environmental Company (SCEC) offers the following comments on behalf of the Cities of Anaheim, Colton and Riverside. All three Cities operate power generating stations that are regulated under RECLAIM.

The Cities of Anaheim, Colton and Riverside (the Cities) operate modern facilities that already incorporate Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT). Municipal power generators have an obligation to provide power to the communities they serve and cannot simply cut back operations due to SCAQMD policies or the implications of SCAQMD's actions on RTC costs and availability. Unlike many facility operators in the South Coast Air Basin that can respond to the proposed NO_X shave by installing new technology or reducing operations, these municipal utilities can only purchase additional NO_X RTCs in order to operate at permitted levels should their existing inventory of credits be discounted. Because of the limited compliance strategies available to municipal utilities and the unique circumstances we face in a regulatory program that is dominated by private sector operators, the Cities feel that they should have been excluded from the RTC reduction proposed by SCAQMD, but we also understand that safeguards can be built into Regulation XX to reduce the impacts of RTC reduction for municipal utilities.

Throughout the rule development process the Cities have stressed that safeguards proposed by SCAQMD to counter the impacts of the RTC reduction must offer certainty that credits will be available when needed, and that those credits can be obtained swiftly and efficiently. The Cities' concerns stem from the uncertainties we will face in the upcoming years as our peaking units are called upon for more frequent run sequences in support of the increased reliance upon renewable resources in the region.

Given that SCAQMD continues to propose a reduction of the Cities' RTC holdings, complementing rule language to ease the burden of the NSR holding requirement for new facilities and to ensure that credits are easily available in the event of RECLAIM or power market upset are critical to the Cities' continued ability to meet their mission as municipal power generators. The Cities appreciate the steps that SCAQMD has taken so far toward meeting the unique needs of municipal power generators, but also recognize that additional thought must be given to several concepts already laid out in Rule 2002. The Cities encourage SCAQMD to continue to refine proposed amendments to Rule 2002 with due consideration of the Cities' needs and we offer these comments for SCAQMD's consideration as it proceeds with its rule development effort.

<u>Rule 2002 (f)(1) - Non-tradable / Non-usable Holdings</u>

SCAQMD proposes to reestablish a non-tradable / non-usable holding account to complement the reduction of available RTCs. Permit holders would be able to access the holding account only after two conditions are met. First the 12-month rolling average RTC price must exceed \$15,000 per ton. Second, the SCAQMD Governing Board must direct staff to convert the holdings to tradeable / usable credits.

Responsiveness of Mitigating Actions

The Cities are concerned that rolling average RTC price may trail too far behind sudden RTC price increases and the requirement to obtain Governing Board authorization to convert the holdings to tradeable and useable credits may not be suitably responsive to our needs as municipal utilities. In other words, the Cities' need for certainty and swift access to RTCs may be jeopardized and we will be forced to participate in a market with escalating costs and limited RTC availability until the point that the \$15,000 threshold is reached. By the time the SCAQMD responses are implemented, it will be too late to undo the damage to the utilities and local communities.

Request for Flexibility in Accessing Non-tradeable / Non-useable Holdings

The Cities understand that other municipal utilities have suggested to SCAQMD that we should have discretionary use of our non-tradeable / non-usable credits for our own use, but not to be sold or transferred to other entities. Those proposals vary from making the credits available at no cost to making them available for a mitigation fee of \$7.50 per pound, which is equivalent to the trigger price of \$15,000 per ton. The fee would be paid only if the holdings are accessed prior to the rolling average price being reached. If the \$7.50 fee were to be assessed, municipal utilities would in effect, access their non-tradeable / non-useable credits only if spot market prices escalate above that rate and would otherwise rely upon the market for any required RTCs.

The Cities are supportive of the proposals to expand access to credits and believe that they would be beneficial to the utilities, SCAQMD and the RECLAIM program in general. By providing access to these credits in advance of a market upset, SCAQMD would provide municipal utilities the certainty needed to meet our mission at a reasonable cost and the limited access of utilities to their non-tradeable credits may actually prevent market upsets that would trigger the widespread release of non-tradeable / non-useable credits to all RECLAIM operators. Finally, if utilities are assessed a fee of for their use of their non-tradeable / non-useable credits in advance of the 12-month price trigger being reached, the proceeds would be available to SCAQMD to facilitate voluntary NOx emission reductions. Those reductions may be more cost-effective than what would otherwise be obtained within the RECLAIM program.

Sunset of Non-tradeable / Non-useable Holdings

The Cities understand that SCAQMD proposes to discontinue the non-tradeable / non-useable holdings in the year 2022. Given the uncertainty presented by increased integration of renewable resources and regional electrification, the Cities ask SCAQMD to provide for continued utilization of the non-tradeable / non-useable holdings, at least for municipal utilities.

Rule 2002 (f)(4) & (5) RTC Adjustment Account

SCAQMD proposes to establish an RTC adjustment account that would serve two purposes. The first is to provide a store of credits that new power generating facilities can use to demonstrate compliance with the NSR holding requirement of Rule 2005 (Rule 2002 (f)(4)). The second purpose of the adjustment account is to make credits available to all power generators in response to an electrical emergency (Rule 2002 (f)(5)). During the August 19 public consultation, SCAQMD indicated that it plans to further refine the provisions of Rule 2002 that deal with the proposed adjustment account. The Cities suggest that the following concepts be given additional consideration.

Compatibility of Dual Purposes

The Cities appreciate that SCAQMD is proposing alternatives that would ease the NSR holding requirement burden and also provide additional RTCs in the event of an emergency. However, it is not clear that both purposes can be simultaneously served, given the amount of RTCs that SCAQMD proposed to allocate to the account. The Cities ask that SCAQMD clarify how the account can be available for emergency use by all power producers, without jeopardizing the ability of new facilities to make the NSR holding demonstration.

During the working group meeting, SCAQMD advised that the proposed funding level of 1 – 1.5 tons/day reflects the amount of reduced RTCs that are currently held by new facilities for the offset demonstration. If the funding of the account reflects the reduced RTCs, rather than the entire PTE for these facilities, it is unclear how the adjustment account can be used by existing facilities (pre 1993 installations) during an emergency without jeopardizing the ability of new facilities to make the NSR demonstration.

Authority to Declare an Energy Emergency

SCAQMD initially proposed that RTCs in the adjustment account would be available to power generators upon an emergency declaration made by the Governor of California, but has committed to investigate concepts that would allow other parties to make such declarations.

Additional entities or authorities should be allowed to declare the presence of an energy emergency at both a regional and local level. Many emergencies requiring local power generation may exist within the boundaries of a city and state or regional authorities may not be able to investigate and make the necessary declaration quickly. Local authorities, such as a City Manager or Mayor, should also be allowed to make a declaration that would allow for the release of RTCs from the adjustment account.

Dispersing Credits from the Adjustment Account

It is unclear how access to RTCs would be granted or how competing applicants would be prioritized by SCAQMD to receive RTCs. SCAQMD must further define its role in the process of granting access to the adjustment account if the Cities are to be assured that credits are available not only for the NSR holding demonstration, but also for easy access in case of an emergency.

RTC Management Flexibility

The Cities ask SCAQMD to clarify how the adjustment account would affect the way in which new power producing facilities would manage the remaining RTCs listed in their facility permits, with respect to the Rule 2005 (f) holding requirement. Ideally, provisions to accommodate the holding requirement would also allow facility operators to sell the remaining unused RTCs listed in their permit in advance of compliance year closure. We also ask SCAQMD to give consideration to the same discretionary use of the adjustment account by municipal utilities that is proposed within this letter for the non-tradeable / non-useable holdings.

Thank you for considering these comments. The Cities of Anaheim, Colton and Riverside welcome the opportunity to further discuss SCAQMD's RECLAIM proposal and I am available should you require additional information regarding the Cities' comments.

Sincerely,
SCEC
An affiliate of Montrose Environmental Group, Inc.

Karl A. Lany
Sr. Vice President

cc: Manny Robledo, Electric Operations Manager, Anaheim Public Utilities
Wayne Feragen, Sr. Plant Manager, City of Colton
Reiko Kerr, Assistant General Manager - Power Resources, Riverside Public Utilities
Chuck Casey, Utility Generation Manager, Riverside Public Utilities

2564.2001Rule 2012ltr4.doc

1631 E. Saint Andrew Place ● Santa Ana, CA 92705 ● (714) 282-8240 ● (714) 282-8247 – Fax
www.montrose-env.com

ECO SERVICES OPERATIONS LLC
DOMINGUEZ PLANT
20720 S. Wilmington Avenue
Long Beach, CA 90810
TEL: (310) 637-8080
FAX: (310) 603-9077

August 28, 2015

Via E-mail: jcassmassi@aqmd.gov

Mr. Joe Cassmassi
Planning & Rules Manager
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

RE: PROPOSED AMENDMENTS TO REGULATION XX:
NOx SHAVE FOR RECLAIM SOURCES

Dear Mr. Cassmassi:

Eco Services Operations LLC (Eco Services) is again writing to express its concerns with the South Coast Air Quality Management District's (SCAQMD's) proposed amendments to Regulation XX to implement the latest round of NO_x emissions reduction for RECLAIM sources ("NO_x shave"). Eco Services owns and operates a sulfuric acid regeneration plant located at 20720 South Wilmington Ave in City of Carson (Dominguez Plant). Eco Services provided comments to you by letter dated April 27, 2015 and is attaching a copy of our prior comments for your reference.

As we previously advised, the Dominguez Plant has been an active supporter and participant of the RECLAIM program. In 2010, Eco Services worked cooperatively with the SCAQMD to identify the Best Available Retrofit Control Technology (BARCT) for the control of SOx emissions and installed a caustic scrubber to greatly reduce SOx emissions at a substantial cost. Eco Services is committed to environmental compliance as demonstrated through our implementation of BARCT for SOx.

As the SCAQMD develops amendments to the RECLAIM program for NOx, Eco Services reiterates its commitment to environmental compliance and working cooperatively towards a common sense and practical solution. Eco Services believes that implementation of technically feasible and cost-effective measure is appropriate. Eco Services is amenable to implement any such measures as we have done with SOx emissions. However, based on the SCAQMD's BARCT analysis, there are no technologies that qualify as BARCT for the NOx emissions sources at the Dominguez Plant. Accordingly, Eco Services is left in the unenviable position of having no practical means of complying with RECLAIM other than purchasing additional allowances at a substantial cost.

Eco Services is very concerned with the prospect of having no control over its ability to comply with RECLAIM. Importantly, we have been advised by RECLAIM brokers that the drastic across the board shave being contemplated by the SCAQMD will result in NOx credits being rendered extremely scarce and accordingly, cost prohibitive. In order for a cap-and-trade program to function properly, there must be a reasonable amount of credits available for trading at a reasonable cost. It is our understanding that NOx credits, if available for trading at all, will be exorbitantly priced.

Eco Services simply does not support a program that leaves no reasonable means of complying other than to put us at the mercy of what we believe will be a dysfunctional trading program. Instead, as we have demonstrated with respect to the SOx RECLAIM program, we support revisions to the RECLAIM program that rely on implementation of feasible and cost-effective controls. Sources that can implement BARCT can and should do so as a first step towards additional reductions. We strongly urge the SCAQMD to consider this approach which will result in a reduction of NOx emissions based on cost-effective controls which will not cripple the RECLAIM trading program and leave smaller emitters no real cost-effective option for compliance. If the SCAQMD pursues the across the board shave, it will effectively be imposing cost-effective requirements on the BARCT sources but not considering cost-effectiveness at all for non-BARCT sources. Eco Services believes that is inequitable and inappropriate.

If the SCAQMD does pursue an across the board NOx shave, Eco Services recommends that the changes to RECLAIM include some type of measure to limit the costs of NOx credits in addition to the current $15,000 per ton annualized average cost, particularly for small emitters. An equitable rule should provide the regulated community with a cost-effective means of complying. We request that the SCAQMD somehow provide a ceiling on the financial impact it will have on RECLAIM participants in terms of cost-effectiveness. BARCT sources will be subjected to cost-effective controls. Similarly, the financial impact to non-BARCT sources should also be based on cost-effectiveness.

It is our understanding that Non-Tradable/Non-Useable allocations will be issued to emitters, and that these "safety valve" allocations can be used as compliance instrument when the average cost of annual NOx RTC exceeds $15,000 per ton (or $7.50 per pound). However, we believe that the time for cost averaging should be significantly shortened to prevent the repeat of situation similar to year 2000 when the value of annual NOx RTC went far above the $7.50 per pound threshold. Also, additional safe guards should be considered to prevent non-compliance for non-BARCT sources if the NOx RECLAIM market fails such that no NOx RTCs are available to be purchased.

If you have any questions or need additional details regarding the information contained in this letter, please contact me at (925) 313-8221.

Sincerely,

Anthony Koo
Sr. Environmental Engineer

cc: Philip Fine, Ph.D., Assistant Deputy Executive Officer, pfine@aqmd.gov
Jill Whynot, Assistance Deputy Executive Officer, jwhynot@aqmd.gov
Gary Quinn, P.E., Program Supervisor, gquinn@aqmd.gov
Kevin Orellana, Air Quality Specialist, SCAQMD, korellana@aqmd.gov

Encl.
{B2213377.1}

ECOSERVICES

ECO SERVICES OPERATIONS LLC
DOMINGUEZ PLANT
20720 S. Wilmington Avenue
Long Beach, CA 90810
TEL: (310) 637-8080
FAX: (310) 603-9077

April 27, 2015

Via E-mail: jcassmassi@aqmd.gov

Mr. Joe Cassmassi
Planning & Rules Manager
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

RE: PROPOSED AMENDMENTS TO REGULATION XX:
NOx SHAVE FOR RECLAIM SOURCES

Dear Mr. Cassmassi:

Eco Services Operations LLC (Eco Services) is writing to express its concerns with the South Coast Air Quality Management District's (SCAQMD's) proposed approach to amending Regulation XX to implement the latest round of reductions in NO_x emissions allowances for RECLAIM sources ("NO_x shave").

Eco Services owns and operates a sulfuric acid regeneration plant (Dominguez Plant) located at 20720 South Wilmington Ave. in City of Carson. The Dominguez Plant's sulfuric acid product is primarily used in petroleum refineries as alkylation catalyst to produce high octane, low vapor pressure, and clean burning gasoline blending stock.

The Dominguez Plant has been an active supporter and participant of the SCAQMD RECLAIM Program. During the 2010 SO_x RECLAIM rulemaking process, Eco Services worked closely and cooperatively with SCAQMD in identifying feasible Best Available Retrofit Control Technology (BARCT) for the Plant. In 2012, the facility became the world's first double absorption sulfuric acid plant to be retrofitted with a caustic scrubber to reduce SO_x emissions. The scrubber has been in operation since November of 2012 and has since been consistently removing approximately 1 ton of SO_x per day from the South Coast Air Basin. These examples serve as a clear indication of Eco Services' commitment to environmental compliance and air quality improvement.

We understand that the SCAQMD is implementing its Air Quality Management Plan (AQMP) and plans to reduce NO_x emissions from its Air Basin. SCAQMD is contemplating on reducing as much as 50% of the currently-available NO_x credit from the Regional Trading Credit (RTC) universe. More importantly, SCAQMD is in the process of evaluating various options on how the reductions will be implemented, including an across-the-board shave approach that would uniformly remove RTCs without consideration of an individual source's operational characteristics or its ability to implement BARCT fundamentally developed for other types of sources.

In 2014, SCAQMD conducted a detailed BARCT study of the major NO_x emitting sources within the South Coast Air Basin. The study did not include the Dominguez Plant because there is no known BARCT available to reduce NO_x emissions at sulfuric acid plants. Furthermore, the study also concluded that the other two natural gas burning sources (the preheater and package boiler) at the Dominguez Plant were not cost-effective for BARCT implementation due to their low usage and NOx emissions.

The Dominguez Plant emits about 0.0685 tons per day of NO_x, which matches its RTC allocations without any surplus. This total represents 0.258% of the entire current NO_x RTC market. Eco Services is concerned that if a 50% across-the-board shave is implemented, it will severely inhibit the Dominguez Plant's ability to comply with the RECLAIM Program. Without a viable BARCT and limited RTC supply, Eco Services is concerned that it will be difficult, if not impossible, for the Dominguez Plant to comply with the post-shave allocation. Assuming that NO_x credits will be available, based on the current credit value of $90 per pound, this translates to an exorbitant minimum of $4,500,000 in compliance costs for the Dominguez Plant.

Eco Services respectfully asks SCAQMD to seriously consider the huge negative impacts to small emitters like the Dominguez Plant, which have no viable options to comply with the proposed NO_x reductions if implemented. Instead, Eco Services urges SCAQMD to consider achieving this round of NO_x reductions by using the sector and subsector approach in lieu of an across-the-board shave. In particular, Eco Services believes that this iteration of the NO_x shave should only be applied to sectors which have viable BARCTs that were identified in the recent BARCT study conducted by the SCAQMD. Applying such an approach, Eco Services respectfully requests that the District remove the Dominguez Plant from the list of facilities subject to this round of the NOx shave.

If you have any questions or need additional details regarding the information contained in this letter, please contact me at (925) 313-8221.

Sincerely,

Anthony Koo
Sr. Environmental Engineer

cc: Elaine C. Chang, D.Ph., Deputy Executive Officer, echang@aqmd.gov
Philip Fine, Ph.D., Assistant Deputy Executive Officer, pfine@aqmd.gov
Jill Whynot, Assistance Deputy Executive Officer, jwhynot@aqmd.gov
Gary Quinn, P.E., Program Supervisor, gquinn@aqmd.gov
Kevin Orellana, Air Quality Specialist, SCAQMD, korellana@aqmd.gov

{B2023836.1}

→ Joe

CHARLES F. TIMMS, JR.
ATTORNEY AT LAW

445 SOUTH FIGUEROA STREET, 31ST FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
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EMAIL: cftimms@aol.com

September 17, 2015

BY EMAIL AND U.S. MAIL

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Re: Follow-up to Comment Letter on NOx RECLAIM Shave Proposal; Cities of Burbank and Pasadena

Dear Dr. Fine:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting this follow-up letter to our August 21, 2015, comment letter on your staff's draft proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), published on July 21, 2015.

We have identified some additional rule language that would need to be amended to facilitate our proposal that power plants be provided with quicker access to non-tradable/non-usable NOx RTCs, and/or access to RTCs in the Adjustment Account, if needed to cover annual emissions. This additional language will ensure that the relevant RTCs are only credited to the SIP on a year-by-year basis to the extent they are not needed for power plant compliance purposes. See Attachment 1 to this letter.

In addition, the Cities support the proposal of the Los Angeles Department of Water and Power to expand the emergency provisions in the staff proposal to allow power plants to access RTCs in the Adjustment Account if an energy emergency alert is declared by the relevant electrical "Reliability Coordinator." See Attachment 2 for proposed rule language.

The Cities appreciate your consideration of these additional comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Jill Whynot, Assistant Deputy Executive Officer (via email)
Attachments.

ATTACHMENT 1

Proposed Amended Rule 2002(f)(1)(J) shall be amended to read as follows:

"The NOx RTC adjustment factors for compliance years 20019 through 2021 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022 NOx RTC adjustment factors shall not be submitted for inclusion in the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year. At the end of each compliance year reconciliation period from 2022 and each year thereafter, the Power Producing Facility shall surrender unused non-tradable RTCs to the District for inclusion into the State Implementation Plan."

ATTACHMENT 2

Proposed Amended Rule 2002(f)(5) shall be amended to read as follows:

"During a State of Emergency as declared by the Governor or an Energy Emergency Alert as declared by the Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the ~~Executive Officer~~ Power Producing Facilities based on the ~~impact that~~ amount of energy they produce during the State of Emergency ~~has on the RECLAIM program~~ or the Energy Emergency Alert."

'Reliability Coordinator' means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL*℠ Company

Mr. Joe Cassmassi
Director, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

RE: 2015 RECLAIM

Dear Mr. Cassmassi:

Southern California Edison (SCE) appreciates the opportunity to comment on the South Coast Air Quality Management District's (District) proposed reduction of Reclaim Trading Credits (RTCs). Moving the District's air basins into attainment is a step toward improved air quality and improved economic growth by increasing the ability of businesses to operate in this region. The District's proposed reduction in the RTC market should act to drive stationary sources under the RECLAIM program to install Best Available Retrofit Control Technology (BARCT) for control of NOx emissions. SCE recognizes the need to make reductions in NOx in order to assist in the effort to achieve attainment with the National Ambient Air Quality Standards.

The shave should drive sources towards BARCT
The shave, as proposed, would constitute a 53% reduction in the total number of RTCs in the market. 67% would be taken from the refinery sector while 47% would be taken from the non-refinery sector, including electric generation facilities. While this would be better than an outright across-the-board shave, it still would trigger costs for the electric generation sector that would have no commensurate impact on reducing air emissions. The electric generation facilities are already at Best Available Control Technology (BACT) with no existing opportunity to reduce emissions (other than curtailing operation, which is not feasible for electric generation facilities since electric demand will dictate operating times). While there is recognition there will have to be some reduction of RTCs from electric generation facilities, the shave should cause facilities not currently at BARCT to install better controls. With the proposed percentages, the costs will disproportionally impact facilities that are already at BACT and result in a subsidization by those at BACT of facilities not yet utilizing the best controls.

The proposed shave amount on the Electric Generation Facilities in effect caps the amount of fuel we can use
As stated above, SCE's electric generation facilities are already at BACT or BARCT, with no currently feasible opportunity, from a control standpoint, to reduce emissions further. With no advancements in control technology, the only way to further reduce emissions is by curtailing operation (i.e. limiting fuel usage). Thus, if no credits were available for purchase on the open market, which is a possibility given the proposed size of the shave, the only way to stay in compliance would be by reducing fuel usage.

P. O. Box 800
2244 Walnut Grove Ave.
Rosemead, CA 91770

Limiting operations might be an option in other industries where production can be outsourced to different sites, but this is not an option for electric generation facilities, as local demand for electricity dictates when these facilities must operate, as ordered by the California Independent System Operator (CAISO). Existing contracts with the California Public Utilities Commission (CPUC) also require the facility to operate when the grid demands it, meaning that when this equipment will run, is effectively out of SCE's control. In other words, if system demand requires SCE to turn on a unit, the facility must do so. SCE will not violate the air permit conditions. But failure to operate when needed for system demand could result power outages.

It should also be noted that under the California Health & Safety Code for market-based programs [§39616(c)], a program must not result in disproportionate impacts to stationary sources in the program as compared to other permitted stationary sources not in the program. A typical permitted source not in the RECLAIM program is subject to rule-based command and control regulations. Were SCE's facilities not in the RECLAIM program, command and control regulations would require BACT concentration limits with no further limits on operation or fuel use, unless such further limits were agreed to for PTE or CEQA limit purposes. However, because the facilities are in RECLAIM, not only are they subject to BACT, but also to the holding requirement and the potential surrender of RTCs. The result is that if there aren't enough RTCs in the market, this proposed shave would effectively cap fuel use. By setting a concentration limit as well as a fuel use limit, this proposed shave would go beyond command and control regulations.

The amount of the shave could have impacts on grid reliability during emergency situations.

The current proposal contemplates what amounts to a 53% shave in the existing RTC market. While action must be taken to reduce current NOx emissions, this action must not result in a situation where generating facilities are unable to operate during emergency situations. The electric grid is a complex, interrelated system. All components work together to generate and ultimately distribute electric power to end users. If, for example, a major transmission line were to go down, there would be an immediate need for local, dispatchable generation to begin operating. If these facilities don't have sufficient RTCs to operate in these circumstances, the system would be faced with energy resources that could not be operated under SCAQMD rules, which would result in load curtailment. Because of the complexity of the system, there is no bright line that can be drawn. The District must therefore exercise caution and not bring about a market that is incapable of responding to emergency situations.

Changes to the RATA testing requirements are supported

Thank you for meeting previously with SCE and DWP on this matter and recognizing that there was a legitimate need to change the rule language regarding postponement of RATAs. In the past, SCE has experienced multiple incidents where equipment has failed in the quarter in which a RATA was due, and found that the District's options for RATA postponement were impractical. With no reasonable alternative to postpone testing, and in order to avoid enforcement, the facilities were forced to petition the SCAQMD Hearing Board for variances. SCE believes the proposed language addresses this issue and now provides a legitimate alternative for RATA postponement without variance relief.

While we fully support the option presented, we are requesting an increase of the 14 unit operating day extension to 30 unit operating days. The main concern is with SCE's Pebbly Beach Generating Station on Catalina Island. Due to its remote location, weather related delays of transportation options to the island, and the high work load schedule of our source testing firm, it can be difficult to organize a RATA test in a short timeframe. The testing firm must separately schedule a time to barge its equipment out to the island, and if power demand on the island were high, the engines may need to run as soon as possible when they return to service, which could impact the test protocol This is especially true for the cleaner engines, as they must operate more frequently in order to comply with facility-wide emission limits. If the source testing firm could not schedule a visit to the island and the engines had to operate to support the power demand, 14 operating days might not be enough time to complete an appropriate RATA. As an alternative, if staff is not open to extending the 14 unit operating day window, SCE suggests having an equivalent operating hour limit. This could give the facility more time to schedule a test without increasing the overall operating time of the unit. Whether there are 14 days or 30 days to complete a RATA, a facility has plenty of incentive to complete the RATA as soon as possible so as to minimize the use of missing data procedures. We ask that the District consider this extension. But other than this amendment, we fully support the rule language as presented by the District and we appreciate the work done by staff to address this issue.

SCE Supports the adjustment account for compliance with Rule 2005 Subdivision (f). Existing USEPA interpretation of the NSR requirements hold that a facility in RECLAIM must obtain sufficient RTCs at the beginning of the calendar year to cover the total potential to emit (PTE) for the year notwithstanding that most facilities do not operate at or near their PTE. This results in a substantial procurement of RTCs that are necessarily bought at a time they are most expensive, but if not used are then sold off when they are of little value. Further, there is no environmental benefit created by what is, in effect, an over-procurement of credits. SCE supports the proposal by the District to create an adjustment account that would cover this RTC requirement. It would eliminate the costly procurement of RTCs beyond what is really needed to cover actual emissions and, quite simply, it makes sense. We urge the District to continue to seek EPA concurrence with this proposal.

As stated above. SCE appreciates the opportunity to provide these comments and we can make ourselves available, if needed, to further clarify our positions. We look forward to working with the District on this important issue.

Sincerely,

Thomas Gross

Thomas Gross

GE
Capital

Mark Mellana
General Manager, Inland Empire Energy Center
800 Long Ridge Road
40434260E
Stamford, CT 06927
USA

T 203 326-7355
mark.mellana@ge.com

September 22, 2015

Ref. No. GE/IEEC – 0905

Joe Cassmassi
Rules and Planning Manager, Planning Rule Development, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: **Inland Empire Energy Center, LLC Request to Change Designation from Investor Category to the Power Plant Category**
RECLAIM XX Rule Making

Dear Mr. Cassmassi:

Inland Empire Energy Center, LLC (IEEC, LLC), a wholly-owned subsidiary of General Electric (GE), is the permit holder for the Inland Empire Energy Center (IEEC). GE partnered with Calpine in 2005 to bring the H-technology gas turbine to life as a demonstration project at the IEEC. For business reasons that existed at the time, GE purchased all NOx RECLAIM Trading Credits (RTCs) required for the IEEC instead of having them purchased directly by IEEC, LLC. The NOx RTCs were acquired specifically and solely to meet the RECLAIM compliance obligations of IEEC, and have been used for no other purpose throughout the life of the project. GE has no interest in any other RECLAIM facility. The GE RTC account is, and always has been, 100% dedicated to the IEEC (please see attachments for evidence of past account transfers).

The current staff proposal for amending South Coast Air Quality Management District (District) Regulation XX incorrectly categorizes the IEEC RTCs held by GE in the Investor category. As the name suggests, the Investor category includes entities that buy and sell RTCs with the objective of making a profit based on fluctuations in market price. The Investor held RTCs are disassociated from any RECLAIM facility. This is clearly not the situation with respect to the IEEC RTCs held by GE.

We suspect that this error occurred because IEEC, LLC is the permit holder for the IEEC, not GE. However, this legal distinction does not change the fact that the subject RTC account is exclusively associated with the IEEC, and is not an Investor account. Because all of the GE owned NOx RTCs were acquired and are used solely for IEEC compliance purposes, GE's NOx RTC account should be designated as a Power Plant (non-refinery) account for purposes of the allocation "shave" in the proposed amendments to Regulation XX.

Failing to correctly categorize the allocations held by GE for IEEC would result in a double digit multi-million dollar impact on our business. IEEC, LLC and GE could have never known that the means by which they chose to acquire and hold the RTCs for the IEEC could have such serious implications, and we do not believe that the District intends such an unforeseen consequence. We therefore request that the GE RTC account be correctly categorized as a Power Plant (non-refinery) account by changing Table 8 in proposed Rule 2002 from Inland Empire Energy Center, LLC to "General Electric Company, Inland Empire Energy Center, LLC

Thank you for your attention to this matter. If necessary to resolve this matter, we would be happy to meet with you and your team to discuss the details of our request. Please coordinate directly with Alisa Moretto at 951-226-4553.

Sincerely,

Francisco Escobedo for

Mark Mellana
General Manager
Inland Empire Energy Center, LLC

cc: Alisa Moretto
Roy Belden

GE
Energy

Tisha Monaco
Sr. Administrative Assistant

Inland Empire Energy Center
26226 Antelope Road
Romoland, CA 92585
USA

T 951 928 5905
Tisha.monaco@ge.com

March 12, 2009

Ref. No. GE/IEEC – 0308

Ms. Susan Tsai
RECLAIM Administration – RTC Transfers
South Coast Air Quality Management District
21865 E. Copley Dr.
Diamond Bar, CA 1765

RE: Inland Empire Energy Center – Form 2007-1 for Delegation of Authority for RTC Transfers & Credits – ID #129816

Dear Susan,

Per our conversation on Tuesday, March 10, 2009, Attached you will find form 2007-1 filled out to make this change giving Delegation of Authority to Francisco Escobedo & Ken Kohl to make RTC Transfers & Credits under ID #129816.

If you have any questions or needs, please do not hesitate to contact me at 951 928 5905.

Thank you,

Tisha Monaco
Sr. Administrative Assistant

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Regional Clean Air Incentives Market Trading Account Representative Registration and Certification Form

Form 2007-1

This form is used to identify the authorized account representative(s) for an RTC holder and/or certify the account status for an RTC trader.

Section I - Account Information

Account Name Inland Empire Energy Center, LLC **Account I.D..#** 129816 (If known)

Account Street Address
26226 Antelope Rd.
Street # 1

Street # 2

Romoland, CA 92585
City, State Zip

Country (if not in the United States)

Mailing Address for Transaction Confirmations
26226 Antelope Rd.
Street # 1, or P.O.Box

Street # 2

Romoland, CA 92585
City, State Zip

Country (if not in the United States)

Section II - Designation of Representatives

Name	Title	Signature	Date
Francisco Escobedo	Director, Asset Managment	Francisco Escobedo	3-12-09
Phone # (951) 928 -5941	Fax # (866) 749 - 9109		
Ken Kohl	Owners Engineer	Ken Kohl	3-11-09
Phone # (518) 385 - 4290	Fax # (999) 221 - 3549		
Name	Title	Signature	Date
Phone # (___) ___ - ___	Fax # (___) ___ - ___		

Section III - Certification Status

I certify that the above named entity is (check boxes below that apply):

Yes	No	
☐	☒	a) Domiciled in the State of California[1]
☒	☐	b) A holder of an active RECLAIM Facility Permit
☐	☒	c) A holder of a pending RECLAIM Facility permit application

If any box is checked "Yes", proceed to Section IV and complete. If all boxes are checked "No", complete Section IV and Attachment A – Designation of Agent for Service of Process and Consent to California Jurisdiction Form

[1] Domiciled in the State of California for the purposes of this form shall be deemed: a) for natural individuals - having permanent and primary residence located in the State of California; (b) for a corporation, firm, association, organization, partnership, business trust or other business entity - incorporated or created pursuant to the laws of the State of California, and in good standing according to the Secretary of the State of California, or (c) for any State or local governmental agency, any subdivisions thereof, or any public district - created and existing pursuant to California State, or local governmental laws and regulations.

Section IV - Certification of Owner or Officer

I certify that I am an owner or officer of the account identified and authorize the above parties to act as the company's representatives in the registration of any transactions for RTCs for the Facility identified herein. I am authorized to make this submission on behalf of the persons with an ownership interest for whom this submission is made. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on 3/12/09 at 10:00 a.m. Romoland, CA, USA
Date *City, State, Country*

Francisco Escobedo Director, Asset Mgmt. (951) 928 - 5941 Francisco Escobedo
Name *Title* *Telephone* *Signature*

This form and SCAQMD's use shall not constitute any acceptance of liability on behalf of SCAQMD for any RTC transaction which may be the result of misrepresentation or error by trading partners or their representatives. This form and SCAQMD's use of it shall not be construed, in any way, to create a fiduciary relationship between it and either the seller or buyer of RTCs or with any other party associated with such transactions.

Submit this form and attachments to:

SCAQMD, RECLAIM Administration - RTC Transfers, P.O. Box 4830, Diamond Bar CA 91765-0830

GE
Energy

Francisco Escobedo
Director, Asset Management

Inland Empire Energy Center
26226 Antelope Road
Menifee, CA 92585
USA

T 951 928 5941
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June 10, 2014

Ref. No. GE/IEEC – 0849

Reclaim Administration – RTC Transfer
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765-0830

SUBJECT: INLAND EMPIRE ENERGY CENTER (IEEC) – 2014 RTC TRANSFER FROM GE ACCT #700126 TO IEEC ACCT #129816

To Whom It May Concern:

Attached is our completed form 2007-2 for the transfer of internal RTC's from the General Electric account #700126 to the Inland Empire Energy Center account #129816. This internal transfer is for the following single year trades:

- 96,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2015 at $0.00/lb/year
- 12,340 lbs of Cycle 2, Coastal zone, RTC's Expiring June 30, 2015 at $0.00/lb/year
- 23,600 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 35,000 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2015 at $0.00/lb/year
- 82,923 lbs of Cycle 2, Inland zone, RTC's Expiring June 30, 2015 at $0.00/lb/year

Since this is an internal transfer, the price is not applicable and there is no purchase agreement or transaction confirmation required.

If you have any questions or need further information, please don't hesitate to contact me at (951) 928-5941.

Sincerely,

Francisco Escobedo

Francisco Escobedo
Director, Asset Management

Enclosure

cc: Christine Stora - CEC

South Coast Air Quality Management District

AQMD

Form 2007-2

Regional Clean Air Incentives Market Trading Credits (RTCs) Transaction Registration

Submit this form and required documents with Transaction Registration Fee pursuant to Rule 301

Mail To:
SCAQMD, RECLAIM Administration - RTC Transfers
P.O. Box 4830
Diamond Bar, CA 91765-0830

Tel: (909) 396-3119
www.aqmd.gov

Name of Buyer/Transferee Inland Empire Energy Center, LLC   Account I.D. # 129816

Name of Seller/Transferor General Electric Company   Account I.D. # 700126

Pollutant: (•) NOx or ( ) SOx *(Identify one pollutant only)*   Is this part of a Swap transaction? ( ) Yes (•) No

Is this form reporting the trade of an Infinite-Year-Block of RTCs? (•) No ( ) Yes

If "Yes," Total Value of Transaction $ N/A ; Enter N/A in the "Price" column below; Report in this form only those RTCs that are traded as part of a single negotiated price. File separate forms to transfer any other RTCs that were negotiated for a separate price.

(Attach a separate form if more than 8 transfers are being registered)

Terms of RTC Transferred			Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price* ($/Pound)	Use Code (Buyer)	Generation Code (Seller)	Account Source Code (Seller)	Origin of Credits (Seller)	Certificate Serial Number (Seller)
Cycle	From Compliance Year*	To Compliance Year*								
1	12/31/2014	Single Year Trade	Inland	23,600	N/A	01	N/A	B	REGXX	N/A
2	6/30/2015	Single Year Trade	Coasta	12,340	N/A	01	N/A	B	REGXX	N/A
2	6/30/2015	Single Year Trade	Inland	82,923	N/A	01	N/A	B	REGXX	N/A
1	12/31/2015	Single Year Trade	Coasta	96,380	N/A	01	N/A	B	REGXX	N/A
1	12/31/2015	Single Year Trade	Inland	35,000	N/A	01	N/A	B	REGXX	N/A

* In the "From Compliance Year" Column, fill in the expiration date of the first compliance year RTCs. The "To Compliance Year" Column is used to enter (1) single year transaction, (2) perpetual stream transaction, or (3) multiple year transaction of RTCs of same zone, quantity, and price in a single line. For a single year transaction, mark this column "Single Year Trade". For a perpetual stream transaction, mark this column "All Years After". For a multiple year transaction, fill in the expiration date of the last compliance year. Use separate lines for transactions of different RTCs, quantities or prices. Transactions for all inclusive years between these two columns will be registered. **See reverse side for examples.**

Buyer Use Codes *(only one code per transaction)*

- 01 Increase RTC Allocation account balance to satisfy annual compliance
- 02 Use under Rule 2005 - New Source Review for RECLAIM
- 03 Increase RTC certificate account balance without issuance of physical certificate.
- 04 Increase RTC certificate account balance with issuance of physical certificate
- 05 Retire RTCs from market without issuance of physical certificate
- 06 Retire RTCs from market with issuance of physical certificate
- 07 Facility Acquisition (Change of Ownership)

NOTE: RTCs in Certificate or Printed Certificate Account must be transferred to Allocation Account to be eligible for compliance use.

Seller Generation Codes

- 01** Process Change
- 02** Addition of Control Equipment
- 03** Production Decrease
- 04** Equipment or Facility Shutdown
- 06 Facility Acquisition (Change of Ownership)
- 07 RTCs for Future Compliance Year, cause of generation not yet been determined

***** Selection of this Generation Code must be accompanied by the selection of Account Source Code "A" - Allocation Account.***

Seller Account Source Code *(only one code per transaction)*

- A Allocation Account
- B*** Certificate Account
- C*** Printed Certificate (must list Certificate Serial number and attach certificate to this form)

****** If this Account Source Code is selected, then select "N/A" from Generation Code field.***

Origin of Credits
State Rule Number from which the credits were originally issued (e.g. Reg XX, R1631, R2506, etc.)

Answer the following Questions:

A. Is this transaction part of a pooled transactions or market?

( ) Yes → Attach Form 2007-3 to identify participants (Part A Only)

(•) No → Go to Question B

B. Is seller an agent, broker, or other intermediary representing the owner of RTC ?

( ) Yes → Attach Form 2007-3 to identify Owner of RTC (Part B Only)

(•) No → Complete this form only

Date when this transaction was agreed upon (trading transaction date): 6/10/2014 → Attach purchase agreement or transaction confirmation

I certify that I am authorized to make this submission on behalf of the affected registered holders of the RTCs listed herein. I certify that the statements are true, accurate, and complete to the best of my knowledge.

Francisco Escobedo
Authorized Representative of Buyer/Transferee *(Print Name)*

Francisco Escobedo
Signature   6/10/2014 Date

Francisco Escobedo
Authorized Representative of Seller/Transferor *(Print Name)*

Francisco Escobedo
Signature   6/10/2014 Date

GE
Energy

Francisco Escobedo
Director, Asset Management

Inland Empire Energy Center
26226 Antelope Road
Menifee, CA 92585
USA

T 951 928 5941
Frank.Escobedo@ge.com

July 21, 2013

Ref. No. GE/IEEC – 0787

Reclaim Administration – RTC Transfer
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765-0830

SUBJECT: **INLAND EMPIRE ENERGY CENTER (IEEC) – 2013 RTC TRANSFER FROM GE ACCT #700126 TO IEEC ACCT #129816**

To Whom It May Concern:

Attached is our completed form 2007-2 for the transfer of internal RTC's from the General Electric account #700126 to the Inland Empire Energy Center account #129816. This internal transfer is for the following single year trades:

- 23,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2013 at $0.00/lb/year
- 12,340 lbs of Cycle 2, Coastal zone, RTC's Expiring June 30, 2014 at $0.00/lb/year
- 96,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 11,400 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 82,923 lbs of Cycle 2, Inland zone, RTC's Expiring June 30, 2014 at $0.00/lb/year

Since this is an internal transfer, the price is not applicable and there is no purchase agreement or transaction confirmation required.

If you have any questions or need further information, please don't hesitate to contact me at (951) 928-5941.

Sincerely,

Francisco Escobedo

Francisco Escobedo
Director, Asset Management

Enclosure

cc: Christine Stora - CEC

South Coast Air Quality Management District

Form 2007-2
Regional Clean Air Incentives Market Trading Credits (RTCs) Transaction Registration

Submit this form and required documents with Transaction Registration Fee pursuant to Rule 301

Mail To:
SCAQMD, RECLAIM Administration - RTC Transfers
P.O. Box 4830
Diamond Bar, CA 91765-0830

Tel: (909) 396-3119
www.aqmd.gov

Name of Buyer/Transferee Inland Empire Energy Center, LLC   Account I.D. # 129816

Name of Seller/Transferor General Electric Company   Account I.D. # 700126

Pollutant: ⦿ NOx or ○ SOx *(Identify one pollutant only)*   Is this part of a Swap transaction? ○ Yes ⦿ No

Is this form reporting the trade of an Infinite-Year-Block of RTCs? ⦿ No ○ Yes

If "Yes," Total Value of Transaction $ N/A ; Enter N/A in the "Price" column below; Report in this form only those RTCs that are traded as part of a single negotiated price. File separate forms to transfer any other RTCs that were negotiated for a separate price.

(Attach a separate form if more than 8 transfers are being registered)

Terms of RTC Transferred			Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price* ($/Pound)	Use Code (Buyer)	Generation Code (Seller)	Account Source Code (Seller)	Origin of Credits (Seller)	Certificate Serial Number (Seller)
Cycle	From Compliance Year*	To Compliance Year*								
1	12/31/2013	Single Year Trade	Coastal	23380	N/A	01	N/A	B	REGXX	N/A
2	6/30/2014	Single Year Trade	Coastal	12340	N/A	01	N/A	B	REGXX	N/A
2	6/30/2014	Single Year Trade	Inland	82923	N/A	01	N/A	B	REGXX	N/A
1	12/31/2014	Single Year Trade	Coastal	96380	N/A	01	N/A	B	REGXX	N/A
1	12/31/2014	Single Year Trade	Inland	11400	N/A	01	N/A	B	REGXX	N/A

* In the "From Compliance Year" Column, fill in the expiration date of the first compliance year RTCs. The "To Compliance Year" Column is used to enter (1) single year transaction, (2) perpetual stream transaction, or (3) multiple year transaction of RTCs of same zone, quantity, and price in a single line. For a single year transaction, mark this column "Single Year Trade". For a perpetual stream transaction, mark this column "All Years After". For a multiple year transaction, fill in the expiration date of the last compliance year. Use separate lines for transactions of different RTCs, quantities or prices. Transactions for all inclusive years between these two columns will be registered. See reverse side for examples.

Buyer Use Codes *(only one code per transaction)*

- 01 Increase RTC Allocation account balance to satisfy annual compliance
- 02 Use under Rule 2005 - New Source Review for RECLAIM
- 03 Increase RTC certificate account balance without issuance of physical certificate.
- 04 Increase RTC certificate account balance with issuance of physical certificate
- 05 Retire RTCs from market without issuance of physical certificate
- 06 Retire RTCs from market with issuance of physical certificate
- 07 Facility Acquisition (Change of Ownership)

NOTE: RTCs in Certificate or Printed Certificate Account must be transferred to Allocation Account to be eligible for compliance use.

Seller Generation Codes

- 01** Process Change
- 02** Addition of Control Equipment
- 03** Production Decrease
- 04** Equipment or Facility Shutdown
- 06 Facility Acquisition (Change of Ownership)
- 07 RTCs for Future Compliance Year, cause of generation not yet been determined

*** Selection of this Generation Code must be accompanied by the selection of Account Source Code "A" - Allocation Account.*

Seller Account Source Code *(only one code per transaction)*

- A Allocation Account
- B*** Certificate Account
- C*** Printed Certificate (must list Certificate Serial number and attach certificate to this form)

*** *If this Account Source Code is selected, then select "N/A" from Generation Code field.*

Origin of Credits
State Rule Number from which the credits were originally issued (e.g. Reg XX, R1631, R2506, etc.)

Answer the following Questions:

A. Is this transaction part of a pooled transactions or market?

○ Yes → Attach Form 2007-3 to identify participants (Part A Only)

⦿ No → Go to Question B

B. Is seller an agent, broker, or other intermediary representing the owner of RTC ?

○ Yes → Attach Form 2007-3 to identify Owner of RTC (Part B Only)

⦿ No → Complete this form only

Date when this transaction was agreed upon (trading transaction date): 6/19/2013 → Attach purchase agreement or transaction confirmation

I certify that I am authorized to make this submission on behalf of the affected registered holders of the RTCs listed herein. I certify that the statements are true, accurate, and complete to the best of my knowledge.

Francisco Escobedo
Authorized Representative of Buyer/Transferee *(Print Name)*

Francisco Escobedo
Signature   6/19/2013 Date

Francisco Escobedo
Authorized Representative of Seller/Transferor *(Print Name)*

Francisco Escobedo
Signature   6/19/2013 Date

Inland Empire Energy Center, LLC
26226 Antelope Rd
Romoland CA 92585

000000001 0000010840 1 1 0684 042 7226

South Coast Air Quality Management
21865 E. Copley Drive
Diamond Bar CA 91765

INVOICE NUMBER	INVOICE AMOUNT	DESCRIPTION
rtc fee 2013	142.17	

CHECK NUMBER	VENDOR NUMBER	DATE	VENDOR NAME	TOTAL AMOUNT
10840	237495101	06/19/13	South Coast Air Quality Management	$142.17

CK0684 v.0.04 09-25-03

ORIGINAL DOCUMENT IS PRINTED ON CHEMICAL REACTIVE PAPER WITH MICROPRINTED BORDER - DO NOT CASH IF THE WORD VOID IS VISIBLE.

Inland Empire Energy Center, LLC
26226 Antelope Rd
Romoland CA 92585

00000

CHECK NO.

64-1278
611

DATE OF CHECK
06/19/13

PAY: **ONE HUNDRED FORTY TWO AND 17/100 DOLLARS**

TO THE ORDER OF SOUTH COAST AIR QUALITY MANAGEMENT
21865 E. COPLEY DRIVE
DIAMOND BAR CA 91765

CHECK AMOUNT
$142.17

Bank of America, N.A.
Atlanta, Dekalb County, GA.

Inland Empire Energy Center, LLC

Authorized Signature

DOCUMENT CONTAINS A TRUE WATERMARK. DO NOT CASH IF THE WATERMARK IS NOT VISIBLE. SEE REVERSE SIDE FOR COMPLETE SECURITY FEATURES.

⑈00000

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

BUYER
ID: 129816

RTC Transfer Confirmation

SCAQMD RECLAIM ADMINISTRATION
P.O. BOX 4830, DIAMOND BAR CA 91765-0830

This letter is to confirm that the South Coast Air Quality Management District (AQMD) has received RTC trading information to comply with Rule 2007-Trading Requirements. The following summarizes your company information and the registration information that you and your trading partner specified in Form 2007-2. The transactions have been recorded and the RTC Listing was updated.

Registration No: 12059

Recording Date: 6/26/13
Pollutant: NOX

	TRANSFER FROM:	**TRANSFER TO:**
Company Name:	GENERAL ELECTRIC COMPANY	INLAND EMPIRE ENERGY CENTER, LLC
Facility ID:	700126	129816
Signing Representative:	Francisco Escobedo	Francisco Escobedo
Mailing Address:	1 RIVER RD SCHENECTADY, NY 12345-	26226 ANTELOPE ROAD MENIFEE, CA 92585-

Terms of RTC Transferred			Original Zone	Quantity (lb/yr)	Unit Price ($/lb)	Use Code	Generation Code	Account Source	Origin of Credits
Cycle	From Compliance Year (*)	To Compliance Year (*)							
1	12/31/2014	Single Year Trade	COASTAL	96,380	0.0000	01	NA	B	REGXX
2	6/30/2014	Single Year Trade	COASTAL	12,340	0.0000	01	NA	B	REGXX
1	12/31/2013	Single Year Trade	COASTAL	23,380	0.0000	01	NA	B	REGXX
1	12/31/2014	Single Year Trade	INLAND	11,400	0.0000	01	NA	B	REGXX
2	6/30/2014	Single Year Trade	INLAND	82,923	0.0000	01	NA	B	REGXX

(*) RTC Expiration Date

Approved By: Jill Whynot

(Signature) JILL WHYNOT
ASSISTANT DEPUTY EXECUTIVE OFFICER
Engineering & Compliance

Code Description :
Use Code (01) : Increase RTC Allocation account balance to satisfy annual compliance
Generation Code (NA) : Not Applicable
Account Source (B) : Certificate

COMMUNITIES FOR A BETTER ENVIRONMENT
EARTHJUSTCE
NATURAL RESOURCES DEFENSE COUNCIL
SIERRA CLUB

July 8, 2015

Philip Fine
Joe Cassmasi
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765
pfine@aqmd.gov
jcassmassi@aqmd.gov

Re: Amendments to Regulation XX – NOx RECLAIM

Dear Dr. Fine and Mr. Cassmassi:

On behalf of Communities for a Better Environment, Earthjustice, Natural Resources Defense Council and Sierra Club ("Health Advocates"), we submit these comments on amendments to Regulation XX, which is slated to go to the Governing Board this fall. We are filing these comments based on the presentation that was provided at June 4, 2015 Working Groups Meeting (hereinafter "Staff Presentation"). At the outset, we remind the South Coast Air Quality Management District ("District") of the urgent ozone and particulate matter problems facing the region. Reducing pollution from the sources in the NOx Regional Clean Air Incentives Market ("RECLAIM") program is essential to achieving our air quality goals and attaining ozone and particulate matter standards. The following sections outline our positions on various issues raised at the last Working Group meeting.

I. The Cap Shave for the Program Should be a Minimum of 14.85 Tons Per Day ("tpd"), Not 14 tpd.

We do not agree with the decision to reduce the total shave amount by .85 tpd, from the required 14.85 tpd to 14 tpd. California's Health & Safety Code is abundantly clear that trading programs must "result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations. . . ." Cal. Health & Safety Code § 39616. In reviewing the materials produced through this rulemaking, the Best Available Retrofit Control ("BARCT") assessments show that a BARCT-equivalent program would result in 14.85

tpd fewer emissions. Accordingly, to comply with Health & Safety Code section 39616, the shave for the RECLAIM program must also be at least 14.85 tpd. We also suggest shaving even more from the program given the large size of the "black box" that must be reduced to meet ozone standards.

II. The Implementation Schedule is Weak.

We are deeply concerned that the schedule for implementation for the shave is too protracted. *See* Slide 4 of the Staff Presentation. Given recent difficulties in meeting various air quality standards, including the 1997 and 2006 standards for fine particle pollution ("PM2.5"), it would be prudent to move up some of the latter year reductions. In fact, we suggest amending the schedule to the following to ensure reductions on the front end in time for compliance with standards.

Year	Current Proposal	Health Advocates Proposal
2016	4 tpd	5 tpd
2018	2 tpd	3 tpd
2019	2 tpd	3 tpd
2020	2 tpd	2 tpd
2021	2 tpd	1.85 tpd
2022	2 tpd	0 tpd

We believe our proposed schedule represents an approach more in line with the directive of the California Health & Safety Code than the implementation schedule proposed in Slide 4 of the Staff Presentation.

III. The District Should Not Establish a New Source Review ("NSR") Set Aside.

Health Advocates do not support the implementation of a District-operated set-aside for New Source Review ("NSR") holdings. There is no basis for the District to undertake this task. In fact, this provision exists to ensure the program does not erode air quality progress in the region. We think this is a necessary safeguard, and we have not heard a compelling reason why the District should take on this duty. Industries have complied with this provision for decades, and it makes sense to continue to place this duty on industry.

IV. The California Environmental Quality Act Analysis Should Examine a Command and Control Alternative.

It is important that the Governing Board and the public receive full information on the environmental landscape of this action. In particular, through the California Environmental Quality Act ("CEQA") process, an assessment of a Command and Control alternative will be important to understand how quickly desperately needed reductions could be implemented in the

South Coast under a regulatory program requiring implementation of readily available technologies, many of which have not been installed at the largest NOx emitters in the South Coast. Under the currently proposed approach, clean up would be protracted for many years as the shave is implemented. A Command and Control Alternative would achieve reductions sooner than this compliance schedule.

V. Industry's Critique on Credit Prices Carries No Water.

At the workshop, representatives for NOx emitters suggested that environmental interests were naïve in solely looking at the prices of short term credits in asserting that NOx RECLAIM credits are priced too low. They claimed that environmental interests failed to look at the price of Infinite Year Block ("IYB") credits. Rather than rebut the claims environmentalists have made that the NOx RECLAIM system is broken because credits prices are too low, the IYB credits only help boost the environmentalists claim. Even with the recent doubling of IYB NOx credits in 2014, the value of IYB credits has been excessively low for over a decade. The following chart from the March 5, 2015 Annual NOx RECLAIM report reprinted below confirms this:

Table 2-5
IYB NOx Pricing (Excluding Swaps)

Calendar Year	Total Reported Value ($ millions)	IYB RTC Traded with Price (tons)	Number of IYB Registrations With Price	Average Price ($/ton)
1994*	$1.3	85.7	1	$15,623
1995*	$0.0	0	0	N/A
1996*	$0.0	0	0	N/A
1997*	$7.9	404.6	9	$19,602
1998*	$34.1	1,447.6	23	$23,534
1999*	$18.6	438.3	19	$42,437
2000*	$9.1	184.2	15	$49,340
2001*	$34.2	416.9	25	$82,013
2002	$5.5	109.5	31	$50,686
2003	$14.3	388.3	28	$36,797
2004	$12.5	557.0	52	$22,481
2005	$43.1	565.3	71	$76,197
2006	$65.2	432.9	50	$150,665
2007	$45.4	233.5	25	$194,369
2008	$49.7	245.6	27	$202,402
2009	$16.7	134.2	14	$124,576
2010	$14.3	149.0	13	$95,761
2011	$9.1	160.7	29	$56,708
2012	$2.2	46.6	13	$48,146

2013	$12.0	260.9	17	$45,914
2014	$99.7	902.2	49	$110,509

District, Staff Report, 2-24, March 6, 2015, *available at* http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-mar6-029.pdf?sfvrsn=2.

The claims of industry lobbyists that the IYB credits are appropriately priced are not true. In fact, like the short term credits, these credits are exceptionally low. Even with a more than doubling of the IYB prices in 2014 compared to 2013, these credits are only 18% of the $609,187 cost established by the District pursuant to section 39616(f) of the California Health & Safety Code, which is set to ensure credit prices do not go too high. That the failure of these IYB credits to even approach 1/5 of the District's ceiling for credit costs just bolsters the excessive number of credits in the NOx RECLAIM system. Overall, the evidence conclusively suggests that the credits are not priced correctly to push for pollution reductions at a level commensurate with what command and control would achieve, which is borne out in the District's BARCT assessments.

VI. The Shave Approach Must Ensure Reductions from Refineries and Powerplants.

The evidence presented by the District in this rulemaking indicates that refineries have used the NOx RECLAIM system as a shield from actually installing pollution control equipment like Selective Catalytic Reduction ("SCR"). Given this past behavior, we suggest that the best path forward is that refineries be taken out of the NOx RECLAIM program and be required to install pollution control equipment.

If this cannot happen, we support the shave approach number 4 on slide 2 of the Staff Presentation, which focuses on large emitters like refineries and natural gas powerplants. Absent removing those facilities unwilling to install pollution controls, this methodology appears to be the most sound approach to allocating the shave of those presented at the June 4, 2015 working group meeting.

Overall, we are deeply committed to ensuring stationary sources clean up harmful NOx emissions in the South Coast. As it stands now, the NOx RECLAIM program has failed to spur adoption of available pollution technologies for many large facilities, and has accordingly failed to adequately reduce NOx emissions. In addition, it has continued to allow high NOx emissions in the disproportionately impacted neighborhoods near refineries and powerplants, raising substantial environmental justice issues. Thus it has dramatically displayed one of the major flaws of a trading system.

We therefore support efforts to retool the program, but urge SCAQMD to do so in a way that meets the urgent need of South Coast residents for clean air and clean energy.

Please do not hesitate to contact us if you have questions.

Sincerely,

Adrian L. Martinez

Adrian Martinez
Elizabeth Forsyth
Earthjustice

Bahram Fazeli
Communities for a Better Environment

David Pettit
Natural Resources Defense Council

Evan Gillespie
Sierra Club

From: Arnie.Smith@Fluor.com
Sent: Tuesday, August 11, 2015 2:16 PM
To: Kevin Orellana
Subject: Re: **SAVE THE DATE** SCAQMD NOx RECLAIM Working Group Meeting
Attachments: AACE_CLASSIFICATION_SYSTEM.pdf

Hi Kevin -

I wanted to share with you this document produced by the Association for the Advancement of Cost Estimating (AACE):

This document highlights the deliverables generated in a gated/phased project development and the corresponding estimate detail and accuracy expected. This is followed by **all** major refining and chemical companies when appraising, selecting, and defining projects for internal funding or external financing. **All** of the major EPCs follow process this as well. Fluor and many other EPCs - and the operating companies - have developed proprietary design manuals that address gated process development and we all follow these very rigorously.

So how does this apply to a NOx RECLAIM Program?

For each potential project, a screening level study estimate (Class 5) is developed for each possible solution for a heater's NOx emissions, for example. Screening whether (1) newer/better burners would be a good choice for NOx mitigation, whether (2) improving the refinery fuel gas for lower NOx generation due to heavy hydrocarbon removal or hydrogen removal, whether (3) improved SCR catalysts would be effective, whether (4) new and/or larger SCR systems are required, or whether (5) the heater should be replaced altogether.

The same would apply to FCC regenerator emissions, but from a slightly smaller list of technical choices.

A variation would apply to sulfur plant incinerators with the caveat that the mitigation system cannot interfere with H_2S destruction during an emergency release.

Following a positive outcome of the screening level study, a more detailed look is undertaken to better define the scope and improve the cost estimate. This estimate is usually an equipment factored or Class 4 estimate.

Following a positive outcome of the more detailed study, the refiner would receive internal funding for a Front End Engineering Design effort, which is of sufficient detail and completeness that external financing could be sought or an internal AFE is pursued. The decision to proceed following a FEED effort is serious since it will involve equipment and construction commodity purchased.

With external financing or an internal AFE, the project can now proceed into the detailed design, procurement, and construction effort.

All this takes time:

- Studies take from weeks to several months to complete, depending on the scope of the problem.
- FEEDs tend to take 6 to 12 months, depending on the project complexity and the impacts to offsites and utility systems.
- EPC is usually 18 to 30 months when new equipment is involved and will depend greatly on the project complexity and its impacts on other systems in the refinery.

In between each of the steps is a review and approval period by the client - likely 1 to 3 months, depending on project complexity and the financial analysis required to move forward.

This disciplined decision making approach is driven by refining being a "commodity" business and one that is extremely capital intensive. Shortcuts do not save time or money. An incomplete technology assessment or rushed project development can lead to regretful choices and inadequate mitigation.

At this point, we are probably one to two months away from having finalized NOx RECLAIM rules. Then, we are only another two months from the beginning of the first compliance year. There will be inadequate time for project development with any results in 2016/2017 - even for simpler scopes like burner replacements in existing heaters or catalyst upgrades in existing SCRs. But, new scrubbers or new SCRs would not be able to provide any mitigation benefit until 2018/2019.

The ongoing SOx RECLAIM Program had a gap of 26 months from the end of rule-making to the beginning of compliance - which would allow for some mitigation to be realized in the first compliance year. A three year gap would have insured an even stronger result.

A three year gap between rule-making and the first compliance year for NOx RECLAIM would have provided a better start for a real NOx reduction.

I am available anytime if you wish to discuss this further.

Thanks and best regards -

Arnie

Arnie Smith | **Fluor** | Executive Director, Process Technology | 3 Polaris Way, Aliso Viejo, CA 92698 | Office: +1 949.349.2231 Mobile: +1 949.322.6985 |
Arnie.Smith@Fluor.com

From: Karl Lany <klany@montrose-env.com>
Sent: Thursday, August 20, 2015 10:58 PM
To: Joe Cassmassi
Cc: Kevin Orellana; Jill Whynot; Gary Quinn
Subject: PAR 2002 RECLAIM and Rule 1146.2 Boilers (Rule 219 exempt)
Attachments: Karl Lany.vcf

Thanks for taking the steps you have to accommodate Rule 219 boiler technology into the proposed RECLAIM amendments. After giving the concept more consideration, I continue to question the proposed requirement that such boilers be subject to testing requirements in order to qualify for RECLAIM reporting factors that reflects certification standards.

Several people at yesterday's meeting raised concerns about the need for, and practicality of, such tests (cost, the presence of certification data, and the way in which certification data supports SIP credit). SCAQMD's position is that certification is for a family of boilers or boiler models, rather than each individual boiler. I understand that concept because of my experience with diesel engine certification programs. There are many parallels that I expect to exist and those parallels lead one to shy away from a testing requirement.

Even though boilers may be certified in groupings, if the boiler program is anything at all like the engine certification program, those groupings are based upon similarity of the equipment, combustion technology and the reasonable expectation that the environmental performance of the lead device truly reflects the environmental performance of the entire family of devices. It seems to me that groups of boilers being certified have very few technological variables. In fact, Rule 1146.2 requires certification based upon each boiler model, which appears to be more restrictive than the engine certification program which includes many different engine ratings and applications in a single family.

As we debate the need for small boiler testing, we should pay close attention to the equity of SCAQMD policy, relative to other certified equipment such as diesel emergency engines that are brought into the RECLAIM program. I recognize I am comparing process units that go through district permitting with Rule 219 permit exempt units, but the comparison is valid because the technology analysis performed by SCAQMD when permitting diesel emergency engines is rather simple.

SCAQMD makes all NSR determinations, including BACT and offset, for certified emergency engines based upon engine certification standards unless the applicant proposes unit-specific certified rates or manufacturer data. SCAQMD does not question the legitimacy of EPA or CARB's certification. Instead SCAQMD makes a very basic determination of the engine certification status and the emission rates to which the engine is certified. SCAQMD then uses the certification status to determine NSR compliance. Then, because Rule 2002 allows, SCAQMD uses the certification standard to determine a RFECLAIM process unit emission factor. The entire SCAQMD program for certified diesel engines rests upon certification standards and excludes any emissions testing. It makes sense that the benefits of certification (exclusion from unnecessary emissions tests) that are extended to process unit diesel engines in RECLAIM would also be extended permit exempt natural gas boilers that arte subjected to a similar certification program.

I sincerely hope that SCAQMD reconsiders its proposed testing requirements for Rule 219 boilers in RECLAIM and instead provides a more practical solution that reflects the legitimacy of its boiler certification program I'm always happy to discuss further at your convenience.

Thanks.

Karl A. Lany
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From: Piantka, George [mailto:George.Piantka@nrg.com]
Sent: Friday, August 14, 2015 4:55 PM
To: Jill Whynot; Joe Cassmassi
Subject: RE: RECLAIM Rulemaking Follow up

Hello Jill and Joe,

I appreciate the time you spent with me last month. I am unclear whether I will be able to make the August 19 RECLAIM Working Group meeting, but nonetheless, we continue to be engaged with the developments of the rulemaking/shave. I have a couple points to consider. I am not considering this formal written comments; just some follow up thoughts. I can give you a call or we can discuss at the August 19 meeting if I can make it.

1. In Rule 2005, will there be proposed language to address annual holding limit requirements for a facility like Walnut Creek. I did not see it, unless I missed it.
2. During our meeting, I may have understated the financial impact to a new facility like Walnut Creek that is different than an existing RECLAIM facility or new plant at an existing RECLAIM facility. In satisfying NSR (unlike a legacy RECLAIM facility), we purchased IYB Cycle 1 and 2 RTCs from the market. Demonstration that we satisfied the RTCs for annual NOx PTE was not only necessary for the Permit to Construct and annual Permit to Operate but also for the financing of the WCEP. We would now represent that the asset has lost the equivalent of 47% of its NOx IYB RTCs at the current rate of say $115/lb-yr and address the means to which we can demonstrate our continued holding and/or access to these RTC for the lenders. While not obvious, the financial implications are different than a facility that has relied on an existing RECLAIM account or the ability to reconcile its emissions for the respective year. It is the difference between losing the unrealized value of IYB RTCs in a legacy RECLAIM account versus the purchase, shave and possible replacement of them at the new market condition (or from the Adjustment Account?) to meet its PTE. This is one of the reasons why we believe WCEP should be exempt from the shave. More food for thought.
3. Any concern about challenges to removal of the annual holding limit requirement by the environmental community?

Thanks for the time. And we can discuss these thoughts soon.

Best Regards,

George Piantka, PE

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From: Jill Whynot [mailto:JWhynot@aqmd.gov]
Sent: Monday, July 20, 2015 10:28 AM
To: Piantka, George
Cc: Joe Cassmassi
Subject: Re: RECLAIM Rulemaking Follow up

George
kid and I can meet at 8:30 tomorrow morning if that would work for you. Call my number and we can let you know what meeting room.
Jill

Sent from my iPhone

On Jul 19, 2015, at 6:47 PM, Piantka, George <George.Piantka@nrg.com> wrote:

> Hello Jill,
>
> Thanks for discussing the proposed RTC shave and more specifically the Walnut Creek Energy Park site – we have annual holding requirements for new equipment (5 LMS 100 gas turbines) that are BACT. Will you have an opportunity to discuss further on Tuesday July 21. I could come in to the District in the morning, before I have to leave for Santa Barbara for a late afternoon meeting. I will unfortunately miss the July 22 workshop meeting, but will have someone monitor the meeting on NRG's behalf.
>
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From:	Casey, Chuck <CCasey@riversideca.gov>
Sent:	Thursday, September 24, 2015 1:20 PM
To:	Kevin Orellana
Cc:	Karl Lany; Perez, James M.; Joel Lepoutre; Feragen, Wayne; Manny Robledo; Marnie Dorsz (mdorsz@montrose-env.com); Wright, Jeffrey
Subject:	bases for inclusion on Top 90% of RTC Holder list
Attachments:	WHEELABRATOR NORWALK ENERGY CO INC 51620.pdf; ALTAGAS POMONA ENERGY INC 176708.pdf; CARSON COGENERATION COMPANY 118406.pdf; CORONA ENERGY PARTNERS, LTD 68042.pdf; HARBOR COGENERATION CO, LLC 156741.pdf; NP COGEN INC 112853.pdf; OLS ENERGY-CHINO 47781.pdf; RegXX Nox shave list July 2015.pdf; SO CAL EDISON CO 4477.pdf; THUMS LONG BEACH 800330.pdf

Kevin,
On behalf of the City of Riverside, City of Anaheim and City of Colton, thank you for your time yesterday regarding an audit of the Preliminary Draft Report – NOx RECLAIM July 21, 2015 Table U.1 "*List of 65 Affected Facilities and Investors.*" The draft report states "*Additionally, all power plants would be included in this option*." (pg 210) but in fact all power plants are NOT included on table U.1.

Attached are the Facilities' "NOx Information" sheets from the AQMD website which appear to hold RTCs and are "power plants" therefore it's a assumed, as per your draft report, would be included on the list but in fact are not. The attachments include power plants such Corona Energy Partners, Wheelabrator Norwalk Energy Co, OLS Energy – CHINO, Carson Cogeneration Company, NP Cogen Inc, Thumbs Long Beach, Harbor Cogeneration Co, and Altagas Pomona Energy inc.

You and I covered a wide range of thoughts yesterday including; ALL power plants are on the list, cogeneration facilities are excluded from the list, "new" power plants are on the list, companies without NSR requirements are excluded, and power plants without any RTCs are not on the list. But in each of these cases I showed how your list contradicts the statement.

For example, you said the list may not include cogeneration facilities even though one of my facilities (facility ID 164204) is on the list and is a cogeneration. Additionally, your familiar with the inclusion of power plants (facility ID 132191 and 132192 for example) with zero RTCs who are on the U.1 list.

In summary, the list as provided in table U.1 needs to be audited with a full explanation of who is included or excluded and the reason for each. The NOx shave percentage adjusted for non-refinery RTC holders' weighted reduction, currently 47%, would require adjustment if the list changes.

Thank you. Please let me know if you have any questions,

Chuck Casey
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Mr. Joe Cassmassi

Los Angeles Department of Water & Power

August 14, 2015

Philip M. Fine, Ph.D., Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

L:

Dear Dr. Fine:

Subject: Los Angeles Department of Water & Power's (LADWP) Comments on Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM

The LADWP appreciates the opportunity to provide comments on the proposed amendments to Regulation XX – NOx RECLAIM and its accompanying Preliminary Draft Staff Report. LADWP remains committed to working with South Coast Air Quality Management District (SCAQMD) to further develop efficient and effective policies to reduce NOx emissions from RECLAIM facilities in order to meet the federal ozone standards in the South Coast Air Basin.

Serving approximately 1.4 million customers in Los Angeles with a generating capacity of over 7,300 megawatts, LADWP is the largest municipal electric utility in the nation, and the third largest electric utility in California. LADWP is a vertically integrated utility, owning and operating a diverse portfolio of generation, transmission, and distribution assets spanning several states.

All of LADWP's generating units are equipped with Best Available Retrofit Control Technology (BARCT) or Best Available Control Technology (BACT) and have reduced NOx emissions by 90 percent. As part of its modernization efforts, since the 1990s, LADWP has been replacing its existing, less efficient utility boilers in the South Coast Air Basin with new, state-of-the-art combined-cycle and simple cycle turbine systems equipped with selective catalytic reduction technology to minimize NOx emissions. During this modernization process, LADWP's generating facilities have been subject to New Source Review and are equipped with BACT.

LADWP also continues to make unprecedented investments in renewable energy resources, energy efficiency and transportation electrification to improve the environment. LADWP is on track to meet 33 percent of its energy sales from renewable energy resources by 2020, has a goal to achieve 15 percent energy savings by 2020, and is continuing to implement programs to support the electrification of the transportation sector to reduce greenhouse gases and criteria pollutants, including NOx, and as a potential solution to absorb over-generation from solar renewable sources.

LADWP's provides comments on SCAQMD's proposed regulatory language and draft preliminary draft staff report below. In addition, LADWP offers a simpler alternate regulatory approach (Pgs. 10 through 14) for the Power Producing Facility sector that is structured to support clean generation and renewable energy while enabling the sector to meet native load and reliably operate.

Comments on the Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

1) Proposed Amended Rule 2002(f) – Annual Allocations for NOx and SOx and Adjustments to RTC Holdings

   a) LADWP is generally supportive of SCAQMD's inclusion of non-tradable RTCs in a Facility Permit Holder's RECLAIM facility account. However, LADWP believes that the current proposed mechanism for accessing the RTCs in a facility's non-tradable account would be costly and inequitably treats Power Producing Facilities that are operating at NOx BARCT levels.

      The proposed rule contains a two-step process before the non-tradable/non-usable RTCs can be converted to tradable/usable RTCs. First, the 12-month rolling average RTC price for all trades (with the exception of transactions at no price or RTC swap transactions) must exceed $15,000 per ton. Second, the SCAQMD Executive Officer would be required to report to the Governing Board at a Board Meeting on the RTC market price. Only upon Board determination that the price threshold of $15,000 per ton was exceeded would the non-tradable RTCs be converted to tradable and usable RTCs. LADWP recommends an alternative approach applicable to Power Producing Facilities such that the non-tradable/non-usable RTCs continue to be deemed non-tradable but *usable* for compliance *without* the price threshold trigger for the following reasons: 18-1

      - All of LADWP's generating facilities have been retrofitted with selective catalytic reduction technology (BARCT/BACT) and have reduced NOx emissions by 90 percent. Thus, LADWP has implemented all feasible NOx controls on-site to control its NOx emissions to the maximum extent feasible.

- As provided in the Los Angeles City Charter, LADWP has the obligation and duty to serve its native load customers. With SCAQMD's proposed 47 percent shave in current RTC holdings, if LADWP were to be short of RTCs, the only compliance option would be to purchase (if available) RTCs at the market price – at whatever that price happens to be. Reducing electricity production at LADWP's Los Angeles basin generating facilities may likely not be an option due to the following operational constraints and needs:
    - Transmission constraints
    - Need for local dispatchable generation to support local renewables
    - Certain minimum amounts of inertia in-basin that are required to import out-of-basin generation 18-1 cont
    - "Reliability Must Run" generation that is needed in-basin
- Although widespread electrification of the transportation sector would result in a *significant net decrease in NOx* emissions in the South Coast Air Basin, there would be a relatively minor increase in NOx emissions at LADWP's generating facilities due to increased electricity demand.
    - SCAQMD, as noted in its 2016 Air Quality Management Plan draft white papers, has stated that there is a need to expand zero-emission technologies in the transportation sector for the South Coast Air Basin to attain the 8-hour ozone standards in 2023 and 2032.
    - The SCAQMD's draft *Residential and Commercial Energy 2016 AQMP* white paper states, "A rough estimate of the NOx emission resulting from upstream power plants providing electricity to the residential and commercial sectors is an additional 1.4 tons per day." This increase in NOx does not include the impacts of electrification of other sectors such as the Goods Movement sector.
    - Having to procure RTCs on the open market to meet native load until the price threshold of $15,000 per ton is reached after investing over

two billion dollars on new advanced gas turbine technology control technology could result in significant additional costs for LADWP.

- These additional costs would likely be, by far, in excess of the proposed $15,000 per ton threshold based on our experience and information in SCAQMD's Annual RECLAIM Report.[1] In particular, RECLAIM RTC prices can be volatile and the market price of RTCs can be significantly high by the time the $15,000 per ton 12-month rolling average price is reached. For example, the average price 1999 NOx RTCs traded in 2000 (1999 cycle 2 RTCs which are valid from July 1, 1999 to June 30, 2000) was $15,369 per ton although 1999 cycle 2 NOx RTCs transacted at significantly higher prices (e.g. $70,000 per ton in the summer of 2000). The average price for NOx RTCs for compliance year 2000 RTCs traded during 2000 increased to $45,609 per ton although there were transactions at the $100,000 per ton level. 18-1 cont.

Thus, the imposition of these incremental costs does not represent an efficient way to achieve the additional NOx reductions needed for meeting the air quality goals in the air basin. In fact, the proposal's process would penalize the Power Producing Facilities which have met NOx BARCT requirements and are making investments in energy efficiency, demand response, energy storage, renewable energy and electric transportation to help meet California's environmental goals as well as help attain the federal ozone standard.

As an alternative to address this concern, LADWP recommends that the non-tradable/non-usable RTCs be deemed non-tradable/usable RTCs such that they are available for Power Producing Facility compliance with NOx RECLAIM. There would be no need for the non-tradable RTCs to be tradable as they would be used strictly for compliance purposes by the affected Power Producing Facility to which the non-tradable RTCs would be allocated. Thus, Power Producing Facilities at BARCT levels would not be subject to the provisions of Rule 2002(f)(D) through (I). To summarize, LADWP would only use the non-tradable RTCs for compliance purposes and allocated tradable RTCs would be used first for compliance and never sold to another electric utility or other entity.

LADWP recommends the addition of the following subparagraph Rule 2002(f)(1)(G) with proposed subparagraphs (G) through (T) renumbered accordingly to (H) to (U):

[1] Annual RECLAIM Audit Report for the 1999 Compliance Year, March 16, 2001

18-1 cont.

> Power Producing Facility Permit Holders listed in Table 8 will obtain tradable/usable NOx RTCs and non-tradable/usable NOx RTCs as listed in subparagraph (f)(1)(C) and shall not be subject to subparagraphs (f)(1)(D) through (F) and (H) through (J). In this subparagraph, a Facility Permit Holder may use its non-tradable/usable NOx RTCs for a compliance year so long as the tradable NOx RTCs were not sold or transferred to another facility not under common ownership during that compliance year.

b) Rule 2002(f)(1)(J) states, "The 2022 NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year." For the 2011 compliance year, SCAQMD submitted the non-tradable/non-usable RTCs for 2011 and all years after to the State Implementation Plan such that RECLAIM facility permit holders' non-tradable RTCs were zeroed out for 2011 and all years thereafter. As mentioned previously, LADWP has an obligation to serve its native load customers and anticipates increased electricity demand in the future due to electrification of the transportation sector. Part of serving native load reliably entails having its in-basin generating facilities available to integrate intermittent renewable energy. LADWP recommends that subparagraph (f)(1)(J) not apply to power producing facilities as they are at BARCT levels and SCAQMD's analysis concluded that there is no new BARCT for the power producing facility sector. Recommended language is in underline/strikeout format: 18-2

> ...The 2022 NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year.
> At the end of each compliance year reconciliation period from 2022 and each year thereafter, the power producing facility shall surrender unused non-tradable RTCs to SCAQMD for inclusion into the State Implementation Plan.

c) Proposed Rule 2002(f)(4) and (5) creates an Adjustment Account for Power Producing Facilities for the purpose of complying with the RECLAIM New Source Review requirements in Rule 2005(f) and compliance with annual emissions. The Power Producing Facilities' ability to access RTCs in the Adjustment Account for the purposes of compliance is constrained such that the RTCs would be released only under the following conditions – the Governor declared a State of Emergency and SCAQMD Executive Officer determination on the impact the State of Emergency has on the RECLAIM program. The suggested language 18-3 also states that the available RTCs for Power Producing Facilities to fulfill compliance with RECLAIM would be limited to the RTCs remaining in the Adjustment Account after Power Producing Facilities' New Source Review offset needs are fulfilled. This introduces great uncertainty whether there will be sufficient RTCs in the Adjustment Account.

LADWP is subject to mandated and enforceable North American Electric Reliability Corporation (NERC) standards which ensure reliability of the bulk power system in North America. LADWP is concerned with respect to its ability to both comply with the reliability standards and the RECLAIM program using the mechanism as proposed. Compliance with NERC standards requires a Power Producing Facility such as LADWP's power plants to respond quickly, as soon as fifteen minutes. Waiting for the Governor to declare a State of Emergency and for the SCAQMD Executive Officer to determine the impacts RECLAIM has on the emergency jeopardizes LADWP's compliance with NERC standards and its ability to reliably deliver electricity to its customers. 18-3 cont.

NERC Reliability Standard EOP-002-3.1 (Enclosure 1) ensures that Reliability Coordinators and Balancing Authorities such as LADWP are prepared for capacity and energy emergencies. Under this reliability standard, the Reliability Coordinator has the authority to initiate an Energy Emergency Alert, as defined, to mitigate the emergency condition.

There are also instances when LADWP, as a balancing authority, must have its Los Angeles basin generating units available for operation to meet NERC standards; if the units are constrained by the unavailability of RTCs, LADWP may face noncompliance with additional NERC standards. For example, there is operational variability in LADWP's current fleet of renewable resources. By late 2016, LADWP will be subject to as much as a 1000 MW sudden drop in output from renewable resources (e.g. due to cloud cover at solar facilities). In order to comply with NERC Reliability Standard BAL-001-2 (which replaces BAL-001-1 on July 1, 2016), LADWP must respond to this variability by dispatching its local generation facilities. That is, as the renewable production (e.g. wind, solar) suddenly decreases, local generation must be rapidly increased, and vice versa. Starting in July 1, 2016, BAL-001-2 (Enclosure 2) will allow only 30 minutes for LADWP to respond to the renewable variability so its Los Angeles basin generating units will be critical resources planned to be used for compliance with this reliability standard.

Also, if LADWP lost a conventional resource, it would have only fifteen minutes to bring up remaining generation to replace the loss. If generation from LADWP's pumped storage hydroelectric generating facility is unavailable, Los Angeles basin generating units would need to come on-line within this fifteen minute time period.

NERC Reliability Standard FAC-011-2, Requirement 2.2 and LADWP's Transmission Reliability Criteria (Enclosure 3) govern transmission operations with respect to system operating limits. Systems such as LADWP's must demonstrate transient, dynamic and voltage stability, facilities must be in operating within their Facility Ratings and within their thermal, voltage and stability limits such that cascading or uncontrolled separation does not occur. LADWP's local transmission system cannot meet this requirement in the absence of local Los Angeles basin generation. Reliability Must Run local generation is required to be either on-line or available to be quickly put on-line to meet the requirement. The only alternative to increasing or turning on the additional generation to meet this reliability requirement would be to shed customer load if insufficient RTCs are unavailable. 18-3 cont.

LADWP recommends the following language in underline/strikeout format:

> During a State of Emergency as declared by the Governor or Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the Power Producing Facility ~~Executive Officer~~ based on the impact that the State of Emergency has on compliance with North American Electric Reliability Corporation standards and the RECLAIM program.
>
> "Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

The draft preliminary staff report states that the Adjustment Account RTCs "would be derived from the proposed programmatic 14 tons per day in NOx reductions." In previous NOx RECLAIM working group meetings, SCAQMD stated that Adjustment Account RTCs derived from the 14 tons per day NOx reductions would not be submitted to the State Implementation Plan. LADWP recommends that the preliminary staff report explicitly state that the Adjustment Account RTCs would not be submitted to the State Implementation Plan. 18-3 cont.

2) Table 6 RECLAIM NOx 2021 Ending Emission Factors
LADWP recommends that the description "Gas Turbines" under the Nitrogen Oxide Basic Equipment column be amended to read "Refinery Gas Turbines" to distinguish that the Power Producing Facility gas turbines are not subject to BARCT in this rule amendment process. 18-4

3) Proposed Amended Rule 2012 – Appendix A: Protocol for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) – Attachment C – Quality Assurance and Quality Control Procedures

a) Semi-Annual Assessments
The proposal's 14 unit operating day time window for conducting a RATA in the case where a major source is physically incapable of being operated is insufficient at LADWP generating facilities when a unit is inoperable for an extended period of time. The draft preliminary staff report includes additional information by stating that the "proposed 14 operating day RATA postponement for unforeseen equipment failure would apply separately for each unrelated, independent event." LADWP supports the clarification in the draft staff report and LADWP recommends that this clarification be reflected in the rule language. LADWP offers the following added language to subparagraph B.2.c after clause B.2.c.ii.: 18-5

> The 14 unit operating day RATA postponement for unforeseen equipment failure applies separately for each unrelated, independent event.

Subparagraph B.2.d. - Due Date for RATAs

LADWP appreciates SCAQMD's efforts to consistently treat facilities under contract with the California Independent System Operator (CalISO) as well as electric generating facilities owned and operated by municipalities that have difficulties in meeting RATA deadlines because their equipment does not operate long enough, or not at all, to conduct a RATA in the quarter in which the RATA is due. 18-6

The proposed rule language states that the electric generating facility can postpone the RATA if it was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due. This means that if the RATA was scheduled during the second 45 days of the calendar quarter, then the RATA cannot be postponed. The draft preliminary staff report does not provide an explanation as to why the RATA must be scheduled the first 45 days of the calendar quarter. There could be situations where a source tester is not available or a unit has not been capable of operating until the second 45 days of the calendar quarter. Thus, the proposed requirement to schedule the RATA during the first 45 days of the calendar quarter does not resolve the availability issues. In both cases, the facilities would need to schedule the RATA in the second 45 days of the calendar quarter to meet compliance. Therefore, so long as the RATA is performed within the required timeframe, facilities should be able to have flexibility with respect to schedule of a RATA. 18-6 cont.

LADWP recommends the following language changes to Clause B.2.d.i. in underline/strikeout format:

> The semi-annual or annual assessment was scheduled to be performed during ~~the first 45 days of~~ the calendar quarter in which the assessment was due

b) Clauses B.2.c.i. and ii – Proposed requirement to disconnect and flange the fuel feed lines when a unit is physically incapable of operation and maintain operational fuel meters introduces health and safety issues, compromises structural integrity of the pipelines and would be costly at steam generating units scheduled to be replaced.

The proposed language requires that:

i. All fuel lines to the major source are disconnected and either flanges or equivalent sealing devices are placed at both ends of the disconnected lines

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site 18-7

Over the next decade, LADWP's steam generating units will be repowered with a combination of more efficient combined cycle units and quick start combustion turbines. These steam generating units have been constructed such that there are no pipe segments of the fuel lines that could be readily removed. To do so, the lines must be cut at two locations and a removable spool would need to be fabricated at significant costs in order to further prove that a unit is inoperable. Also, this requirement would unnecessarily create a health and safety risk as the fuel lines are insulated with asbestos-containing materials (ACM) at two of LADWP's generating stations. The intact ACM would have to be removed to gain access to the fuel pipelines which would be against the general plant operating and maintenance practice and EPA's recommendation to leave intact ACM alone.

LADWP surveyed all of its generating units that are currently in operation. The survey presented technical difficulties of creating air gaps by cutting into the fuel lines or removing certain piping equipment including valves, strainers, or meters to create the gaps. LADWP has considered alternative methods to pipe cutting and removing equipment such as opening access to the piping and equipment. 18-7 cont.

LADWP recommends the following changes to Clauses B.2.c.i. and ii:

i. All fuel lines to the major source are disconnected or opened and either flanges or equivalent sealing devices are placed at both ends of the disconnected or opened lines

ii. The fuel meter(s) for the disconnected or opened fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site

Alternative Regulatory Approach

As discussed above, reducing NOx emissions at in-basin plants may not be feasible due to the fact that the only way to achieve additional reductions from these well-controlled plants is by reducing their generation output. As discussed above, reducing the utilization of in-basin gas-fired generation is not a viable option given the essential role these units play in ensuring a reliable supply of electricity in the basin.

Furthermore, an essential part of the strategy to reduce NOx emission levels in the South Coast Air Basin will be to electrify the transportation sector and other major source categories of NOx emissions. Specifically, the increased electricity generation will result in small increases in NOx emissions by affected electric generating units, but those emission increases will be more than offset by substantial NOx emission reductions achieved by the newly electrified sources. Electrification of even a portion of these sources will result in substantial overall net NOx emission reductions in the SCAB region. 18-8

LADWP has identified a possible regulatory credit mechanism that could be developed to ensure that affected power plant facilities would not be penalized for increased NOx emissions resulting from an increased demand in electricity due to native load needs and increased transportation electrification. Such a crediting mechanism would incentivize the development and implementation of renewable energy and transportation electrification. This approach would be consistent with SCAQMD's position as described in its comment letter to U.S. Environmental Protection Agency (EPA), which states that "It is important that the 111(d) regulation recognizes California's unique situation and does not hinder the introduction of additional renewable energy generation." "The proposed regulation must be structured to support clean generation and renewable energy."[2]

In addition, this proposed regulatory mechanism is consistent with the federal Clean Air Act framework for achieving expeditiously the air quality goals established under the Act. Most importantly, the establishment of a mechanism to enable the achievement of substantial overall net NOx reductions in the South Coast Air Basin region will provide an effective strategy for the SCAQMD to meet its "reasonable further progress" reduction goals for the current 2008 ozone standard as well as any additional NOx reductions that may be necessary for meeting upcoming more stringent ozone standard. 18-8 cont.

The discussion below describes how a similar credit mechanism might be developed to ensure affected electric generating facilities had sufficient RTCs in the event that SCAQMD decides to impose an across-the-board RTC reduction on all affected RECLAIM facilities.

1. <u>Quantify the amount of RTCs needed to support native load and transportation electrification</u>

   The first step of the process would involve each affected electric utility quantifying the amount of NOx RTCs that it would need to cover its projected NOx emissions. The process for calculating each unit's generation level would be based on the amount of electricity that the utility would need to

[2] November 26, 2014 letter to EPA regarding *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units – Proposed Rule*

generate in order to meet its native load, along with the expected electricity demand increase resulting from the transportation electrification. This determination would likely be based on an Integrated Resource Plan (IRP) or similar process for estimating the utility's native load and the expected transportation electrification for the next 10 to 15 years. With respect to transportation electrification, the utility would need to work with the SCAQMD and the California Air Resources Board (CARB) to estimate the level of transportation electrification in the basin in order to determine the resulting increased electricity demand.

Based on this quantification of future electricity demand and NOx emissions (which could be updated on an annual basis), the SCAQMD would allow the affected electric utilities to hold in their accounts sufficient number of NOx RTCs to cover their emissions on a system-wide basis. This amount of each utility's RTCs would not be deducted from its RECLAIM account and consequently remain available for use in meeting its RECLAIM credit-holding requirements.

2. <u>Determine the amount of RTCs used for electrification of major NOx emission source categories</u> 18-8 cont

Each utility sector would quantify the number of RTCs that are actually used to generate electricity for electrification of mobile sources and other major NOx source categories in the South Coast Air Basin region.

In the case of electric vehicles, this quantification would be performed for each compliance year based on a method similar to CARB's Low Carbon Fuel Standard approach. A combination of meter kWh data and estimated kWh data applied to the number of EVs that a utility reports would be used to quantify the emissions due to the increase in electricity demand from electric transportation.

In the case of the other major NOx source categories, the quantification would be performed based on the estimated NOx emission reductions that would occur from mandatory electrification measures established by the CARB and SCAQMD as well as non-mandatory electrification measures and incentives that CARB, SCAQMD and electric utilities may promote.

3. <u>Label unused RTCs designated to cover electrification as non-tradable</u>

The RTCs that an electric utility retains based on the quantification of future electricity demand due to electrification would be put into a utility's account and labeled non-tradable. The non-tradable RTCs could be used for compliance purposes only and allocated tradable RTCs would be used first for compliance. Thus, if a utility has NOx emissions that are lower than expected such that its non-tradable RTCs are unused, the utility would not be able to sell them to entities outside of the utility's system. At the end of the reconciliation period, the utility would surrender unused non-tradable RTCs to SCAQMD for credit toward reducing NOx emissions through the RECLAIM program and meeting attainment of the ozone standard. Enclosed is a more detailed description of this regulatory approach (Enclosure 4).

<u>State Implementation Plan crediting with respect to design of the NOx RECLAIM program to accommodate transportation electrification</u>

18-8 cont.

There are uncertainties with respect to the level of electrification and the level of in-basin generation needed to support future renewables which creates uncertainties as to the number of RTCs that electric generating facilities would need. LADWP believes that SCAQMD has the discretion to develop its NOx RECLAIM program to accommodate such uncertainties without having to determine the exact amount of the NOx reductions upfront for SIP credit purposes. Enclosed for your review is a white paper that outlines the key elements of an emission reduction crediting mechanism that SCAQMD could use to account for and provide the appropriate emission reduction credit to electric utilities for the overall net NOx emission reductions achieved by the electrification of other source categories in order to meet its "reasonable further progress" goals under the Clean Air Act (Enclosure 5). Among other things, the paper presents the key design elements of a crediting mechanism that is modeled after approaches that EPA has developed for promoting energy efficiency and renewable energy measures under the Clean Air Act.

LADWP is ready and willing to work with SCAQMD, CARB, and EPA to explore opportunities in creating an approach to include the benefits of transportation electrification as well as support clean generation and renewable energy. Development of an EPA-recognized SIP crediting mechanism will address the regulatory uncertainty that would otherwise result from this paradigm shift and thereby encourage the implementation of policies to reduce emissions from the transportation and major source categories of emissions through electrification in the South Coast Air Basin and other urban ozone nonattainment areas.

Finally, in the NOx RECLAIM working group meeting on July 9, SCAQMD stated that resolution language would be included in this NOx RECLAIM rulemaking package to address the impacts of transportation electrification on the RECLAIM program. LADWP offers that resolution language to address this issue (Enclosure 6). 18-8 cont.

Again, LADWP appreciates the opportunity to provide comments on the NOx RECLAIM proposed amended rules and draft preliminary staff report. If you have any questions or would like additional information, please contact Ms. Jodean Giese of my staff at (213) 367-0409.

Sincerely,

Mark J. Sedlacek

Mark J. Sedlacek
Director of Environmental Affairs

JG:dms
Enclosures
c: Ms. Jill Whynot, SCAQMD
Mr. Joe Cassmassi, SCAQMD
Ms. Jodean Giese

A. Introduction

1. **Title:** **Capacity and Energy Emergencies**
2. **Number:** EOP-002-3.1
3. **Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   4.1. Balancing Authorities.
   4.2. Reliability Coordinators.
   4.3. Load-Serving Entities.
5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff:

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts."

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable.

1.3. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	[illegible]	[illegible]	[illegible]
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to "Requirement 6" instead of "Requirement 7"	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. "Applicability."	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted "4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to "2.1"	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.
3	August 5, 2010	Adopted by NERC Board of Trustees	New
3.1	March 8, 2012	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed	Errata

		references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	
3.1	September 13, 2012	FERC Approved	Errata

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

   1.1. Situations for initiating alert. An Energy Emergency Alert may be initiated for the following reasons:

   - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers.

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform

[1] For emergency, not economic, reasons.

the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**

2. **Number:** **BAL-001-2**

3. **Purpose:** To control Interconnection frequency within defined limits.

4. **Applicability:**

 4.1. Balancing Authority

  4.1.1 A Balancing Authority receiving Overlap Regulation Service is not subject to Control Performance Standard 1 (CPS1) or Balancing Authority ACE Limit (BAAL) compliance evaluation.

  4.1.2 A Balancing Authority that is a member of a Regulation Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Regulation Reserve Sharing Group.

 4.2. Regulation Reserve Sharing Group

5. **(Proposed) Effective Date:**

 5.1. First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Responsible Entity shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R1.

M2. Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years unless, directed by its Compliance Enforcement Authority, to retain specific evidence for a longer period of time as part of an investigation. Data required for the calculation of Regulation Reserve Sharing Group Reporting Ace, or Reporting ACE, CPS1, and BAAL shall be retained in digital format at the same scan rate at which the Reporting ACE is calculated for the current year, plus three previous calendar years.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 100 percent but greater than or equal to 95 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 95 percent, but greater than or equal to 90 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 90 percent, but greater than or equal to 85 percent for the applicable Interconnection.	The CPS 1 value of the Responsible Entity, for the preceding 12 consecutive calendar month period, is less than 85 percent for the applicable Interconnection.
R2	The Balancing Authority exceeded its clock-minute BAAL for more than 30 consecutive clock minutes but for 45 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 45 consecutive clock minutes but for 60 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 60 consecutive clock minutes but for 75 consecutive clock-minutes or less for the applicable Interconnection.	The Balancing Authority exceeded its clock-minute BAAL for greater than 75 consecutive clock-minutes for the applicable Interconnection.

E. Regional Variances

None.

F. Associated Documents

BAL-001-2, Real Power Balancing Control Performance Standard Background Document

Version History

0	February 8, 2005	BOT Approval	New
0	April 1, 2005	Effective Implementation Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	July 24, 2007	Corrected R3 to reference M1 and M2 instead of R1 and R2	Errata
0a	December 19, 2007	Added Appendix 2 – Interpretation of R1 approved by BOT on October 23, 2007	Revised
0a	January 16, 2008	In Section A.2., Added "a" to end of standard number In Section F, corrected automatic numbering from "2" to "1" and removed "approved" and added parenthesis to "(October 23, 2007)"	Errata
0	January 23, 2008	Reversed errata change from July 24, 2007	Errata
0.1a	October 29, 2008	Board approved errata changes; updated version number to "0.1a"	Errata
0.1a	May 13, 2009	Approved by FERC	
1		Inclusion of BAAL and WECC Variance and exclusion of CPS2	Revision
1	December 19, 2012	Adopted by NERC Board of Trustees	
2	August 15, 2013	Adopted by the NERC Board of Trustees	
2	April 16, 2015	FERC Order issued approving BAL-001-2	

Attachment 1
Equations Supporting Requirement R1 and Measure M1

CPS1 is calculated as follows:

$$CPS1 = (2 - CF) * 100\%$$

The frequency-related compliance factor (CF), is a ratio of the accumulating clock-minute compliance parameters for the most recent preceding 12 consecutive calendar months, divided by the square of the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\varepsilon 1_I)^2}$$

Where $\varepsilon 1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon 1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon 1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon 1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon 1_I$ = 0.021 Hz

The rating index $CF_{12\text{-month}}$ is derived from the most recent preceding 12 consecutive calendar months of data. The accumulating clock-minute compliance parameters are derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.
A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{RACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum RACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10B}$$

And,

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor ($CF_{\text{clock-minute}}$) calculation is:

$$CF_{\text{clock-minute}} = \left[\left(\frac{RACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, 60 clock-minute averages of the reporting Balancing Authority's Reporting ACE and Frequency Error will be used to compute the hourly average compliance factor ($CF_{\text{clock-hour}}$).

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) and the data samples for each 24-hour period (one for each clock-hour; i.e., hour ending (HE) 0100, HE 0200, ..., HE 2400). To calculate the monthly compliance factor (CF_{month}):

$$CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

To calculate the 12-month compliance factor ($CF_{\text{12 month}}$):

$$CF_{\text{12-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-i})]}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})-i}]}$$

To ensure that the average Reporting ACE and Frequency Error calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50 percent of both the Reporting ACE and Frequency Error sample data during the one-minute interval is valid. If the recording of Reporting ACE or Frequency Error is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the CPS1 calculation.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its CPS1 performance after combining its Reporting ACE and Frequency Bias

Settings with the Reporting ACE and Frequency Bias Settings of the Balancing Authority receiving the Regulation Service.

Attachment 2

Equations Supporting Requirement R2 and Measure M2

When actual frequency is equal to Scheduled Frequency, $BAAL_{High}$ and $BAAL_{Low}$ do not apply.

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times \left(FTL_{Low} - F_S\right)\right) \times \frac{\left(FTL_{Low} - F_S\right)}{\left(F_A - F_S\right)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times \left(FTL_{High} - F_S\right)\right) \times \frac{\left(FTL_{High} - F_S\right)}{\left(F_A - F_S\right)}$$

Where:

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW)

$BAAL_{High}$ is the High Balancing Authority ACE Limit (MW)

10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz

B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz)

F_A is the measured frequency in Hz.

F_S is the scheduled frequency in Hz.

FTL_{Low} is the Low Frequency Trigger Limit (calculated as $F_S - 3\varepsilon1_I$ Hz)

FTL_{High} is the High Frequency Trigger Limit (calculated as $F_S + 3\varepsilon1_I$ Hz)

Where $\varepsilon1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon1_I$ = 0.021 Hz

To ensure that the average actual frequency calculated for any one-minute interval is representative of that time interval, it is necessary that at least 50% of the actual frequency sample data during that one-minute interval is valid. If the recording of actual frequency is interrupted such that less than 50 percent of the one-minute sample period data is available or valid, then that one-minute interval is excluded from the BAAL calculation and the 30-minute clock would be reset to zero.

A Balancing Authority providing Overlap Regulation Service to another Balancing Authority calculates its BAAL performance after combining its Frequency Bias Setting with the Frequency Bias Setting of the Balancing Authority receiving Overlap Regulation Service.

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Operations Horizon**

2. **Number:** FAC-011-2

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** April 29, 2009

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies

R2.3.3. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R3.2. Selection of applicable Contingencies

R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.

R3.4. Level of detail of system models used to determine SOLs.

R3.5. Allowed uses of Special Protection Systems or Remedial Action Plans.

R3.6. Anticipated transmission system configuration, generation dispatch and Load level

R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology (Retirement approved by FERC effective January 21, 2014.)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.
R3.6	N/A	N/A	N/A	N/A
R4	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3

Requirement	Lower	Moderate	High	Severe
	OR For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to30 days after the effectiveness of the change.	OR For a change in methodology, the changed methodology was provided to one or more of the required entities more than30 calendar days after the effectiveness of the change.
R5 (Retirement approved by FERC effective January 21, 2014.)	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

   1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

   1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

   1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

   1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

   1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

   1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

   1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

   1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

   1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

   1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

   1.2.2 Cascading does not occur.

   1.2.3 Uncontrolled separation of the system does not occur.

   1.2.4 The system demonstrates transient, dynamic and voltage stability.

   1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

   1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	

AUGUST 18, 2015

Framework for NO_x RTC Allocations

This paper provides an informal outline of a possible framework for the allocation of NO_x RTCs to the electric generating units (EGUs) under the RECLAIM program. The objective of this proposed framework is to establish an effective regulatory approach for AQMD to meet its ozone reasonable further progress goals for reducing NO_x emissions under the Clean Air Act. The NO_x emissions for EGUs represent a very small share (less than 3 tons per day during 2011-2013) of the total NO_x emissions in the region (about 550 tons per day estimated for 2016). Part of the strategy to reduce NO_x levels in the region is to electrify sources that are currently burning fossil fuels. Specifically, the increased electricity generation will result in small increases in NO_x at EGU, but those emissions will be more than offset by substantial NO_x emission reductions at the newly electrified sources. Several of those source categories provide large opportunities to reduce overall NO_x emissions: off road equipment, locomotives, ships and commercial boats, and passenger vehicles, SUVs and light duty trucks. Electrification of even portion of these sources will result in substantial overall NO_x reductions. The AQMD's forecasts indicate NO_x reductions in excess of 200 tons per day from forecast 2023 levels are required to keep the region on track for attainment of the current 2008 ozone standard. Notably, electrification of sources that currently burn fossil fuels also increases efficiency so it will be an important tool in achieving the ozone NAAQS as well as the California's CO_2 emission goals under federal and state regulatory programs.

As reflected in the matrix below, the proposed approach would establish the following three "building blocks" for the allocation of NO_x RTCs to affected EGUs: (1) Tradable RTCs allocated to serve native load (forecast demand absent additional electrification programs); (2) Non-tradable RTCs allocated to cover increased generation resulting from mandatory electrification measures established by the ARB or AQMD; and (3) Non-tradable RTCs allocated to cover increased generation resulting from non-mandatory electrification measures and incentives that the ARB, AQMD or electric utilities may promote. Under the proposed approach, RTCs allocated under building block 1 cannot be reduced under any circumstances given that they need to cover native load, while RTCs allocated under building blocks 2 and 3 can be adjusted to reflect the actual amount of increased demand that results from electrification measures actually implemented.

There are several ways that the AQMD could incorporate the non-mandatory electrification measures and incentives into its SIP and receive NO_x emission reduction credit for meeting its ozone reasonable further progress goals under the Clean Air Act. One such approach is the "state measure" approach[1] that EPA has established for a state to meet its applicable CO_2 emission rate target under the Clean Power Plan. In so doing, EPA states that the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve specified portion of the required emission performance level on behalf of affected EGUs. The key difference between the traditional federal-state regulatory approach and EPA's "state measures" approach is that instead of private entities, such as affected EGUs, being responsible for obtaining specific emission reductions, the state adopts a plan that makes itself responsible for ensuring the implementation of the particular state measures in order to meet its federal emission reduction obligations. A similar regulatory approach could be implemented by the AQMD in order to meet its ozone reasonable further progress goals for reducing NO_x emissions under the Clean Air Act.

Finally, it should be noted that EPA has suggested that a "state measure" approach should include a number of key measures in order to guarantee the achievement of the targeted emissions reductions. In particular, it may be necessary for a state to support its state measures with clear initial demonstrations that the required reductions will be achieved, regular reporting during the compliance period, and clear contingency and federally enforceable backstop measures if the expected emission reductions are not achieved by the state. In the case of the non-mandatory electrification measures, AQMD may need to include backstop provisions that automatically place a federally enforceable control measures on NO_x sources in the region to secure any reductions that the state plan commitments do not deliver. The AQMD would choose the appropriate backup reduction measures. However those federally enforceable measures should most likely apply to sources other than power plants given that EGUs are regulated to the maximum extent feasible under AQMD's plan (*i.e.*, EGUs are operating to meet native load or supply electricity for electrification measures that are achieving a net NO_x reduction.)

[1] Another approach not discussed in this paper to provide SIP credit for non-mandatory electrification measures based on the guidance that EPA has developed for how states can earn SIP credit for state implementation of energy efficiency and renewable energy measures under its SIPs.

	RTC Allocation	Types of Credits	SIP Implications
Building Block 1	RTCs are allocated at sufficient levels to cover NO_x emissions from affected EGUs that operate at levels necessary to serve electricity demand within the South Coast Air Basin. RTC allocations are based on stringent NO_x BARCT emission rates set for highly efficient gas-fired generation. RTC allocations are based on utilization levels that are necessary for affected EGUs to meet forecast demand absent additional electrification programs. RTC allocation is sufficient to cover NO_x emissions attributable for startups and shutdowns.	The RTCs are tradable. The RTCs cannot be reduced given that they are essential for EGUs meeting electricity demand and doing so at the lowest feasible NO_x emission rate.	Since BARCT is imposed on all affected EGUs, they are already well-controlled sources that are doing their share to meet RFP goals for reducing NO_x emissions in the South Coast Air Basin.
Building Block 2	An incremental allocation of RTCs is allocated to cover NO_x emissions attributable to incremental electricity demand (beyond Building Block 1) for the implementation of mandatory electrification measures under the state implementation plan.	The RTCs are non-tradable. The number of RTCs can be adjusted to reflect the actual amounts of increased electricity demand attributable to the mandatory electrification	Federally enforceable SIP measure Because the NO_x reductions result from mandatory electrification measures, incremental RTCs to EGUs will not result in a net NO_x emission increase. Furthermore,

	RTC Allocation	Types of Credits	SIP Implications
	For example, an incremental allocation of RTCs could be allocated for the increased generation attributable to mandatory requirements to electrify additional operations at the Port of Los Angeles, LAX, or other significant sources of NO_x emissions.	measures. This incremental allocation of RTC will result in a net reduction in NO_x emissions in the South Coast Air Basin due to offsetting NO_x emission reductions achieved from the mandatory electrification measures.	there is no question on whether there will be a net NO_x reduction, but rather only a question on how many reductions will be achieved (dependent on the source converting to electricity).
Building Block 3	An additional allocation of RTCs is allocated to cover NO_x emissions attributable to incremental electricity demand (beyond Building Blocks 1 and 2) that result from non-mandatory (voluntary) electrification measures. For example, there are many possible policies, incentives, and other measures that the State, City, AQMD, or electric utilities may undertake to encourage the electrification of the transportation or other NO_x emitting sectors. To the extent that these efforts result in the electrification, then there will be a net NO_x emission	The RTCs are non-tradable. The number of RTCs can be adjusted to reflect the electricity demand attributable to the mandatory electrification measures	There are several possible ways to reflect the non-mandatory electrification measures in the SIP. One possible way is to follow the "state measure" approach proposed by EPA in the Clean Power Plan. Under this approach, the AQMD or the State would make a commitment to achieve a specific amount of NO_x reductions through the implementation of voluntary measures referenced in the SIP. Although further EPA guidance is needed, it is likely that AQMD will need to provide enforceable

	RTC Allocation	Types of Credits	SIP Implications
	reduction even though NO_x emissions from affected EGUs will slightly increase.		regulatory backstop measures that would be activated in the event that the NO_x reductions are not achieved. However, the backstop provisions would apply to sources other than power plants given that EGUs are regulated to the maximum extent feasible (i.e., EGUs are operating to meet native load or supply electricity for electrification measures that are achieving a net NO_x reduction.) Another possible way to include non-mandatory measures in the SIP is through existing EPA policy guidance that allows the use of energy efficiency measures and renewable energy generation to achieve emissions reductions under certain situations.

AUGUST 18, 2015

SIP CREDITING MECHANISM TO PROVIDE CREDIT FOR REDUCTIONS ACHIEVED THROUGH ELECTRIFICATION

OUTLINE OF KEY ELEMENTS

The objective of this white paper is to outline the key elements of an emission reduction crediting mechanism that state or local regulatory authorities, such as the South Coast Air Quality Management District (AQMD or District), can use to account for and provide the appropriate emission reduction credit to electric utilities for the overall net NO_x emission reductions achieved by the electrification of other source categories under their state implementation plan (SIP). The paper begins with a brief discussion on the need for the Environmental Protection Agency (EPA) to establish such a SIP crediting mechanism and then presents the key design elements of a crediting mechanism that is modeled after approaches that EPA has developed for promoting energy efficiency and renewable energy measures under the Clean Air Act (CAA).

Need for SIP Crediting Mechanism

The attainment and maintenance of the current 2008 national ambient air quality standard for ozone will require substantial NO_x emission reductions from the largest source categories of NO_x emissions in the South Coast Air Basin (SCAB). As a result, AQMD is examining various NO_x emission reduction strategies, including a substantial reduction in the NO_x RTC holdings for all affected RECLAIM facilities, in order to meet its "reasonable further progress" (RFP) goals for reducing NO_x emissions under the CAA. This need for NO_x emission reductions in the SCAB will only increase when EPA adopts (as expected) final rules to tighten the current ozone standard in October 2015.

According to the District, an essential part of the strategy to reduce NO_x emission levels in the SCAB region will be to electrify the transportation sector and other major source categories of NO_x emissions. Specifically, the increased electricity generation will result in small increases in NO_x emissions by affected electric generating units (EGUs), but those emission increases will be more than offset by substantial NO_x emission reductions achieved by the newly electrified sources. Electrification of even portion of these sources will result in substantial overall net NO_x emission reductions in the SCAB region.

One key implementation issue relates to how the AQMD can account for and provide appropriate emission reduction credit to electric utilities for the net NO_x emission reductions achieved by the electrification of other source categories under the District's ozone attainment SIP. At present, there does not exist an EPA-recognized SIP crediting mechanism for electrification that the District could use for meeting its ozone RFP reduction obligations under the CAA. Without such a crediting mechanism, it is difficult for the AQMD to allocate in advance an additional amount of NO_x RTCs to affected EGUs – even though this increased RTC allocation is necessary for the electrification of the other major sources that will achieve an overall net NO_x reduction within the SCAB region.

The establishment of such a SIP crediting mechanism for electrification is needed not only for the SCAB region, but other major urban areas with significant ozone nonattainment problems for which electrification of major NO_x source categories will likely become an important ozone attainment strategy. Furthermore, the need for such a SIP crediting mechanism is particularly important given that many of the measures for promoting electrification may be non-mandatory policies and incentives that are not federally enforceable under the CAA. The use of non-mandatory policies and incentives in SIP attainment strategies is major shift in the typical CAA regulatory paradigm of states developing SIP control strategies that impose federally enforceable emissions reduction requirements on affected emission sources. The establishment of EPA-recognized SIP crediting mechanism will therefore address the regulatory uncertainty that would otherwise result from this paradigm shift and thereby encourage the implementation of policies to reduce emissions from the transportation and major source categories of emissions through electrification in the SCAB and other urban ozone nonattainment areas.

Key Design Elements of SIP Crediting Mechanism

The purpose of this paper is to identify the key design elements of a SIP crediting mechanism that state or local regulatory authorities, such as AQMD, can use to account for and provide appropriate emission reduction credit to electric utilities for emission reductions achieved by the electrification of other source categories with the same region under their SIP attainment strategies. This proposed SIP crediting mechanism is based on similar approaches that EPA has developed for incorporating energy efficiency and renewable energy strategies into SIP attainment strategies under CAA section 110[1] and state plans for meeting its applicable CO_2 emission reduction targets under CAA section 111(d).[2]

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[1] *See* Guidance by EPA Office of Air Quality Planning and Standards, entitled: *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans* (July 2012) (hereinafter referred to as "*EPA Roadmap*").
[2] *See* Proposed Clean Power Plan, 79 Fed. Reg. at 34,902.

As a general matter, EPA has interpreted the CAA to require that four criteria must be satisfied in order for an emission control measure to generate creditable emission reductions that can be used for meeting its RFP goals in the SIP attainment strategy. These criteria are that the emission reductions are: quantifiable, permanent, surplus, and enforceable. The discussion below presents the design elements of a SIP crediting mechanism that would satisfy each of these criteria.

Quantifiable. In order for a policy or measure to be quantifiable, the state or local regulatory authority must quantify the overall net emission reductions that would result from the implementation of the policy or measure for electrification. This analysis would require a quantification of the NO_x emission reductions that are projected to occur as a result of the electrification of existing sources of NO_x emissions in the nonattainment area. One challenge would be the quantification of NO_x emission reductions resulting from the implementation of non-mandatory policies and incentives to encourage electrification. In addition, the analysis should include a quantification of projected NO_x emission increases that would likely occur due to the increased generation of electricity by EGUs located in the nonattainment area. EPA guidance should be developed on each of these steps of analysis in order to ensure consistency among states on how to quantify the overall net reductions that result from electrification policies and measures.

Permanent. The state or local regulatory authority must show that the emission reductions from the electrification policies and measures will not be temporary, but will continue through the future attainment date. To that end, the regulatory authority should develop policies and measures that reflect long-term commitments for electrification and include in its SIP control plan a demonstration on why these commitments will yield extended emissions reductions that satisfy the criterion for permanency.

Surplus. The electrification policies and measures must not be otherwise required under the CAA.[3] To meet this criterion, the state or local regulatory authority would need to demonstrate in its SIP submission that these policies and measures are additional to the control measures included in the baseline emissions projections for the SIP attainment strategy so that there will be no double counting of emission reductions. One element of this demonstration should include a certification that the regulatory authority has reviewed the electrification control strategies and confirms that these strategies are not being used to claim emission reduction credits in any of control strategies included in the SIP attainment strategy, as well as a description of specific

[3] Section 173 (c)(2) of the CAA (providing that "Emission reductions otherwise required by this chapter shall not be creditable as emissions reductions for purposes of any such offset requirement").

steps that the regulatory authority is taking to ensure that there is no double counting of emission reductions.

Enforceable. There would be two pathways from demonstrating compliance with this criterion. The first, and most straightforward, pathway would be the adoption of mandatory control measures that would directly or indirectly require the electrification of the affected sources of NO_x emissions in the nonattainment area. Such mandatory measures would be federally enforceable against specific entities which must be able to verify compliance with the specific control requirements and be subject to enforcement for the failure to comply with those requirements, including civil penalties and corrective action.

The second pathway would be the adoption of non-mandatory policies and incentives for encouraging electrification. Under this alternative approach, the regulatory authority would have the option of meeting the criterion for enforceability through the adoption of an enforceable commitment requiring the regulatory authority to evaluate the effectiveness of the non-mandatory electrification policies or incentives and, if these measures do not achieve the projected emission reductions, to remedy any SIP reduction shortfall. This remedy may involve the implementation of contingency control measures to achieve the necessary emission reductions or demonstrating that the emission reductions are not needed to achieve the RFP reduction requirements for attaining the ozone standard.

Such an approach, as noted above, is modeled after the federal guidance that EPA has developed for incorporating energy efficiency and renewable energy strategies into SIP attainment strategies under CAA section 110.[4] Importantly, the EPA guidance describes four possible implementation pathways for incorporating energy efficiency and renewable energy policies and programs into SIP control strategies. One such pathway involves the adoption of non-mandatory policies and programs to encourage the use of energy efficiency and renewable energy.[5] To meet the enforceability criterion, the state or regulatory authority must make an enforceable commitment to:

- Implement those parts of the policies or measures for which the agency are responsible;
- Monitor, evaluate, and report at least every three years on progress toward emission reductions; and

[4] *See EPA Roadmap*. Notably, this guidance draws from previously issued EPA guidance documents that seek to encourage states to incorporate energy efficiency and renewable energy measures into their SIP control strategies.
[5] *See EPA Roadmap* at pages 9 and 30-32.

- Remedy any SIP credit shortfall if the policies or measures do not meet the projected emission reductions.[6]

In addition, this approach for meeting the enforceability criterion is consistent with the "state measure" approach that EPA has proposed for a state to meet its applicable CO_2 emission rate target under the Clean Power Plan. In this case, EPA has proposed to allow a state to achieve a portion of its CO_2 emission reduction obligation through enforceable requirements to increase renewable energy, energy efficiency, and perhaps other control methods that do not apply directly to EGUs. In so doing, EPA states that the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve specified portion of the required emission performance level on behalf of affected EGUs. The key difference between the traditional federal-state regulatory approach and EPA's proposed state measure approach is that instead of private entities, such as affected EGUs, being responsible for obtaining specific emission reductions, the state adopts a plan that makes itself responsible for ensuring the implementation of the particular measures in order to meet its federal emission reduction obligations.

[6] *See EPA Roadmap* at page 37.

RESOLUTION NO. 15-XXX

A Resolution of the South Coast Air Quality Management District Board Recognizing the Need to Increase the NO_x RTCs Allocations for Affected Electric Generating Units in order to Achieve National Ambient Air Quality Standards

WHEREAS, the attainment and maintenance of the national ambient air quality standards for ozone will require substantial NO_x emission reductions from the largest source categories of NO_x emissions in the South Coast Air Basin (SCAB).

WHEREAS, the largest source categories of NO_x emissions in the SCAB include off road equipment (43 tons per day), locomotives (22 tons per day), ships and commercial boats (41 tons per day), and passenger vehicles, sport utility vehicles, and light duty trucks (24 tons per day);

WHEREAS, the District is currently examining possible regulatory strategies for achieving NO_x reductions from these and other source categories through the electrification of combustion sources;

WHEREAS, the regulatory strategies under consideration include both mandatory and voluntary measures for electrification of combustion sources that would be incorporated into the state implementation plan and achieve substantial NO_x emission reductions that are required for meeting the obligations of the South Coast Air Quality Management District under the federal Clean Air Act; and

WHEREAS, the electrification of these other source categories will require substantial increases in electricity generation from affected electric generating units (EGUs) within the SCAB and that such increases in electricity generation will result in a corresponding increase in NO_x emissions from affected EGUs.

THEREFORE, BE IT RESOLVED that the Board of the South Coast Air Quality Management District commits to provide in the future an additional allocation of NO_x RECLAIM Trading Credits (RTCs) to affected EGUs in order to cover the additional NO_x emissions attributable to such increased electricity generation.

BE IT FURTHER RESOLVED that this future increased allocation of NO_x RTCs to affected EGUs does not constitute a change to the New Source Review regulations that is prohibited under the provisions of Senate Bill 288, entitled *The Protect California Air Act of 2003* and codified at Health and Safety Code §§ 42500-42507, but rather is fully consistent with the goals and protections afforded under Senate Bill 288 given that—

- any additional NO_x emissions from affected EGUs in the SCAB would be offset by a significantly greater reduction in NO_x emissions from other sources within SCAB for an overall net air quality improvement; and

- affected EGUs have already installed the most stringent NO_x control technologies currently available and, consequently, that the NO_x emissions from such EGUs comprise only a very small share (less than 3 tons per day during 2011-2013) of the total NO_x emissions in the SCAB (about 550 tons per day estimated in 2016).

Shell Trading

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August 6, 2015.

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Subject: Proposed Amendments to Regulation XX – NOx Reclaim

This letter includes Shell Energy's comments to the proposed amendments to Regulation XX – NOx RECLAIM. Shell Energy and Wildflower Energy are parties to an Energy Conversion Agreement dated July 26, 2004 (the "ECA"). Under the ECA, Shell Energy has the right to direct that fuel be converted into energy by the Indigo Generated Units that are located in SCAQMD territory.

After analyzing the Draft Rule Language released on July 22, 2015 and participating in the public workshop about this topic we would like to submit the following comments for your consideration:

- The Indigo Facility was built in response to the California Energy crisis in 2001. Indigo was constructed with BACT - best available control technology – including a CO catalyst and SCR to limit NOx to 5 ppm. It operates at a very low capacity factor as this technology is only needed during periods of high demand on the grid, although the SCAQMD permit requirements obligate the facility to hold offsets for significantly greater operational hours. Typically, SCAQMD considers the cost effectiveness of emission reductions, and will evaluate a cost benefit analysis. To meet the proposed requirements in Rule XX, the facility would need to make significant modifications to the SCR, CO catalyst and to the exhaust modules housing the catalyst, far exceeding typical cost benefit ratios. The alternate emissions reduction choice would be to replace the combustor on the gas turbine, also cost prohibitive. There is no further cost effective NOx reduction technology for this facility. The only way that such Facilities can comply with the current proposed rule is to purchase additional NOx RTCs. This represents a significant expense for generating facilities especially considering the current market conditions in California, including the recent decommissioning of San Onofre Nuclear Generating Station. We request that SCAQMD consider that peaking generation facilities with lower capacity factor built to BACT should not be obligated under the proposed rule to make further emissions reductions, and allow the emissions offsets previously procured for the unit to meet current and future SCAQMD requirements.

1C1-1

- Rule 2002 Section PAR 2002(f)(1)(B) and (C) state that the Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of March 20, 2015 by adjustment factors for the relevant compliance year. Setting the Amendment Date after it had passed is equivalent to retroactive ratemaking and could have unintended economic consequences. We believe that the Date of Amendment should be set closer to or upon the actual date when the final Rule is published. Additionally, it is not clear how the March 20, 2015 date was established and does not address how NOx RTCs that were transferred between March 20, 2015 and the date of the implementation of the Proposed Rule will be treated. We request the SCAQMD act prospectively; the NOx RTC holdings should be the quantity as of the date of the implementation of the Proposed Rule. 19-2

- Additional information and clarification is needed regarding the Proposed Adjustment Account for Generators PAR 2000 (f) (4). 19-3

We appreciate your consideration of the comments above and look forward to continuing this conversation. Please don't hesitate to contact me at (858) 526-2103 if you would like to discuss our comments.

Yours truly,

Manuel Robin for Michael D. Evans

Michael D. Evans
Regulatory Manager

cc: Wildflower Energy LP
C/O Diamond Generation Corporation
333 S. Grand Ave., Suite 1570
Los Angeles, CA 90071
Attn: Vice President, Asset Management
Facsimile: 213-620-1170

Bracketed Pages from Final PEA

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Attachment 1 to this letter provides more detailed comments on this draft PEA from WSPA's technical consultant, and are hereby incorporated by reference. ("Attachment 1"). 2-3

WSPA has previously submitted numerous comments on the proposed regulation itself, as well as the notice of preparation and initial study ("NOP/IS") for the draft PEA, but these comments have received insufficient attention from the District in its environmental analyses.[1] The District responds to the NOP/IS Letter by claiming that technical analyses have been considered, when an in-depth evaluation of the industry's technical concerns has not been performed. 2-4

WSPA has serious concerns with both the proposed rule amendments and the draft PEA, and believe that the requirements under the California Environmental Quality Act ("CEQA") have not been satisfied. Furthermore, both the proposed amendments and the draft PEA must be revised and recirculated to address the comments raised by WSPA and the numerous other commenters in order to correct errors, disclose all significant impacts, and allow the consideration of feasible mitigation measures or project alternatives to reduce or avoid these impacts. 2-5

I. Fundamental Problems With The Draft PEA Undermine The Environmental Analysis

Under CEQA, an EIR is an informational document designed to provide public agencies and the public with detailed information about the impacts that a proposed project is likely to have on the environment, analyze the ways in which the significant effects of a project might be minimized, and identify alternatives to the project.[2] The District's draft PEA, as a substitute EIR under its certified regulatory program, is also subject to the substantive provisions of CEQA.[3] 2-6

Fundamental flaws in the draft PEA's project description and objectives, the scope of review, and the selection and analysis of alternatives, pervade the document, ultimately resulting in a misleading document in specific resource areas as well. Many of the errors in the draft PEA are related to problems with the methodology, assumptions,

[1] See, in particular, the letter submitted by WSPA dated August 21, 2015 on the preliminary draft staff report ("PDSR") and Attachments 1 and 2 (hereinafter referred to as "WSPA's August 21 Letter"). See also the January 30, 2015 letter submitted by WSPA as part of the Industry RECLAIM Coalition commenting on the NOP/IS (the "NOP/IS Letter"), and WSPA's May 27, 2015 letter on the April 29, 2015 SCAQMD NOx RECLAIM Working Group Meeting. For convenience, these letters are provided as Attachments 2, 3 and 4 to this letter.

[2] Pub. Resources Code §§21002, 21002.1(a), 21061; 14 Cal. Code Regs. §15362; see also Pub. Resources Code §§21100, 21150.

[3] 14 Cal. Code Regs. §15250; *City of Morgan Hill v. Bay Area Air Quality Management District*, 118 Cal.App.4th 861, 874-875 (2004).

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The draft PEA should identify realistic assumptions based on facts to properly evaluate potential environmental effects of construction activities, and a one-size fits all approach that dismisses the potential for environmental effects based on the industrial locations of the facilities is not sufficient. 2-14

In short, the PEA makes unsubstantiated industry-wide generalizations in determining that technology is feasible, implementation timeframes are reasonable, the site specific impacts will be negligible, and the individual businesses will perform as expected. These generalizations cannot support the PEA's assumptions, particularly in light of the District's own third party expert's efforts to correct the errors in its technical analysis. If an EIR is "so fundamentally and basically inadequate and conclusory in nature" that public comment on the draft is essentially meaningless, or if significant new information is added to an EIR, it must be recirculated for further public review.[15] The PEA should be revised to substantiate its assumptions and reevaluate its conclusions accordingly, and should then be recirculated for further public review and comment. 2-15

B. The PEA Purports To Be A Program-Level Document, But Construction Activities Generally Require Project-Level Review

The draft PEA is described as a "program CEQA document" ostensibly because it consists of proposed amendments to Regulation XX.[16] As noted above, however, the draft PEA appears to evaluate BARCT construction activities, and specific construction projects generally require a project-level analysis. This distinction is important because a program-level review can be more abbreviated and the District apparently seeks to utilize that approach, but it has now embarked on a partial project-level review of BARCT construction activities. As noted above, noise is dismissed in the PEA and not evaluated at all, even though noise is an environmental topic commonly reviewed in a project level EIR for a construction project. If the District seeks to transform a rule-making into a construction project, it needs to do so in compliance with CEQA. 2-16

Furthermore, the draft PEA, which is a "substitute CEQA document" pursuant to the District's certified regulatory program, states that the "program" CEQA document may be used by other agencies for "future related actions." Section 15253 of the CEQA Guidelines addresses use of a substitute CEQA document by responsible agencies, and the District should clarify how the provisions of that Section have been satisfied. 2-17

The draft PEA's insufficient project level analysis for BARCT construction activities reinforces WSPA's main critique of the District's proposed amendments to Regulation XX—the technical analysis to support the proposed amendments is 2-18

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[15] *Laurel Heights Improvement Ass'n v Regents of Univ. of Cal.*, 6 Cal.4th 1112 (1993); 14 Cal. Code Regs. §15088.5(a).

[16] Draft PEA, p. 1-3.

ATTACHMENT 1

ADDITIONAL WSPA COMMENTS ON
DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT (PEA)
FOR NO_X RECLAIM AMENDMENTS

Page/Section	WSPA Comment	
Page 1-1, 3rd paragraph	This paragraph describes the project as "amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements <u>and to modify the RECLAIM trading credit (RTC) "shaving" methodology</u>." [emphasis added] This description is not consistent with the project description contained in the AQMD's Notice of Preparation issued 4 December 2014,[1] nor is the description consistent with Project Description contained in the Initial Study.[2] Specifically, neither the NOP Project Description nor the Initial Study Project Description includes any reference to modifying "the RECLAIM trading credit (RTC) "shaving" methodology" in the description of the project or the project objectives.	2-49
Page 1-1, 4th paragraph	The Draft PEA states that "further analysis of the actual BARCT NOx emission control opportunities for the various equipment/process categories demonstrated that the proposed project could achieve 14 tons per day of NOx emission reductions by 2023 which is much higher than estimates provided in the 2012 AQMP." While this value is certainly much higher than contemplated in the 2012 AQMP, it is also <u>not supported</u> by the AQMD Staff's technical analysis.[3] The Staff's analysis does not support a 14 ton per day (TPD) shave as necessary for BARCT equivalency. Rather, the Preliminary Draft Staff Report (PDSR) very clearly demonstrates that not more than 8.79 TPD of emission reductions from the RECLAIM program can be attributed to BARCT advancement; a conclusion that is later echoed in the Draft PEA.[4] Furthermore, a 14 TPD shave reduction of the RECLAIM market may violate the project objectives under the California Health & Safety Code (H&SC). Contrary to H&SC §40406, Staff have failed to take into account the economic impacts for each class or category of source. The Staff analysis only considers costs and cost effectiveness for the BARCT equivalency amount of 8.79 TPD (i.e., advancement from 2005 BARCT to 2015 BARCT). There is absolutely no consideration of the economic impacts which would be incurred by RECLAIM facilities under a 14 TPD market adjustment that goes beyond BARCT.	2-50

[1] AQMD, Notice of Preparation of a Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014. See "Description of Nature, Purpose, and Beneficiaries of Project."

[2] AQMD, Initial Study for Draft Program Environmental Assessment, Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), December 2014. See page 1-7, Project Description.

[3] AQMD, Preliminary Draft Staff Report (PDSR) for Proposed Amendments to NOx RECLAIM, 21 July 2015.

[4] AQMD, Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 15 August 2015. See Table 1-3.

1

Page 2-6, 4th paragraph	The Draft PEA states "the proposed project is estimated to reduce four tons per day of NOx emissions starting in 2016 because the amount of unused RTCs in the NOx RECLAIM program over the past five years (e.g., from 2009 to 2013) ranged from five tpd to eight tpd, demonstrating that there is enough cushion to support reduction of four tpd in 2016." While the quantities of "unused" RTCs are a matter of historical record, Staff has provided no evidence to support that supposition that the RECLAIM market has "enough cushion to support reduction of four tpd in 2016." And if this was just a reduction of unused RTCs, that would not equate to an emissions reduction in 4 TPD. The Draft PEA needs to be revised to include a market analysis to support that supposition or this statement should be deleted.	2-69
Page 2-6, 4th paragraph (continued)	The Draft PEA goes on to state "it could take from two to four years for the affected facilities to plan, obtain permits, and install air pollution control equipment or modify existing equipment in response to the proposed project." According to information from WSPA members, this estimate is too short.[26] While some individual projects might be complete able in 2-4 years, the proposed project would require dozens and dozens of emission control projects to be completed. For the refinery sector, such projects would need to be planned, engineered, and sequenced for construction in consideration of unit turnaround schedules. WSPA members report that completion of all needed projects for the proposed project would likely require not less than eight (8) years. The Draft PEA should be revised to reflect this timetable and the Proposed Amended Rules and PDSR should be similarly adjusted.	2-70
Page 2-9, PAR 2005 Requirements for New or Relocated RECLAIM Facilities – Subdivision (b)	The AQMD Staff have yet to provide a complete description of the amendments to this rule. AQMD Staff have also not obtained U.S. EPA approval that such amendments would even be approvable into the State Implementation Plan (SIP). The Draft PEA and PAR 2005 should be revised to reflect these important details after AQMD Staff have obtained the U.S. EPA approval needed for such amendments to be legal.	2-71
Page 2-10, top of page	The Draft PEA states "Further, only 44 facilities are expected to comply with the proposed NOx RTC shave through the purchase of RTCs which will have no environmental impact." The Draft PEA should be revised to present supporting analysis demonstrating how this conclusion was reached.	2-72
Page 3.2-34, 2nd paragraph, GHG Tailoring Rule	This section should be revised to note that the courts vacated significant portions of the GHG Tailoring Rule. The applicability criteria as described in the Draft PEA are not consistent with current regulations.	2-73
Page 4.1-3, Section 4.1.3.1	The Draft PEA states "Because each affected facility is located in heavy industrial areas, the construction equipment is not expected to be substantially discernable from what exists on-site for routine operations and maintenance activities. Further, the construction activities are not expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities are expected to occur within the confines of each existing facility and are expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility."	2-74

[26] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.

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	This statement oversimplifies the range of physical settings existent for RECLAIM facilities. In actuality, some refinery or non-refinery RECLAIM facilities are located areas where additional vertical obstructions from cranes or new emission control structures could be "discernable" and may adversely impact views and aesthetics resources for adjacent communities. The Draft PEA should be revised to clarify the range of settings which would be impacted by the proposed project and acknowledge the range of potential impacts associated with the proposed project.	2-74 Con't
Page 4.2-2, Table 4.2-1 Estimated Number of NOx Control Devices Per Sector and Equipment/Source Category	As shown in this table, the Draft PEA states that Staff has assumed 74 SCRs would be installed on Refinery Process Heaters and Boilers under the proposed project. Staff does not explain the basis for this value, which conflicts with the Preliminary Draft Staff Report (PDSR). The PDSR suggests that the proposed project would result in 76 SCRs (25 upgraded, 51 new) for refinery heaters and boilers,[27] in which case the Draft PEA would be understating the potential project impacts. It should also be noted that AQMD's third-party refinery sector expert, Norton Engineering, found that only 48 refinery heaters and boilers could be cost effectively retrofit with new or upgraded SCRs.[28] Staff have done nothing to reconcile this discrepancy which is material. The Draft PEA must be revised to clarify the technical basis for the assumed emission controls outcome and associated potential impacts to the environment. The Draft PEA should also explain how emission controls which are not cost effective, according to AQMD's own third-party expert, will be implemented.	2-75
Page 4.2-4, Section 4.2.3.1, first paragraph	The Draft PEA states "Further, operators at each affected facility who construct NOx control equipment that utilize chemicals as part of the NOx control equipment operations, such as a new ammonia or caustic storage tank, may also need to build a containment berm large enough to hold 110 percent of the tank capacity in the event of an accidental release, pursuant to U.S. EPA's spill prevention control and countermeasure regulations." While other regulations and good engineering practices would require containment features for these tanks, the Spill Prevention Control and Countermeasure (SPCC) regulations actually don't apply to ammonia or caustic storage vessels. The Draft PEA should be clarified accordingly.	2-76
Page 4.2-7, last paragraph	The Draft PEA states "if a particular technology was identified as having a cost that exceeds $50,000 per ton, this CEQA analysis assumed that the facility operator would not install this type of air pollution control technology in response to the project." This statement is inconsistent with the project objectives which require compliance with the California Health & Safety Code. The $50,000 threshold fails in this regard. Under H&SC§39616(c)(1), the RECLAIM program is required to result in "an equivalent or greater reduction in emissions **at equivalent or less cost compared with current command and control regulations** and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment." AQMD Staff has failed to demonstrate that the proposed amended RECLAIM program will be **at equivalent or less**	2-77

[27] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, Table B.10.
[28] AQMD Preliminary Draft Staff Report, Proposed NOx RECLAIM Amendments, July 2015, Table B.9.

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Comment Letter #3

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October 6, 2015

BY EMAIL (BRADLEIN@AQMD.GOV) AND U.S. MAIL

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South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4178

Re: Comment Letter on Draft Program Environmental Assessment for Proposed Amended Regulation XX; Cities of Burbank and Pasadena

Dear Ms. Radlein:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting the following comments on the Draft Environmental Assessment ("Draft PEA") for the proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), for which a Notice of Completion was published on 3-1 August 13, 2015. The Draft PEA purports to contain an analysis of the potential adverse environmental impacts that could be generated from the proposed project. Unfortunately, the Draft PEA does not contain any analysis of the potential adverse environmental impacts of the potential shortage of RECLAIM Trading Credits ("RTCs") for future power plant needs, which is of great concern to the Cities. 3-2

While the NOx shave proposal appears to include provisions that would mitigate some of its worst impacts on the Cities' well-controlled power plants, it still does not provide the needed certainty that adequate RTCs will be available at a reasonable price to cover these plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies. We have suggested some improvements to the proposal that would provide the needed certainty and address other issues (see the Cities' comment letter on the proposed rule 3-3

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Page 2

dated August 21, 2015). In the absence of these improvements, the NOx shave proposal may have significant adverse air quality impacts that should be addressed in the Final PEA. 3-3 Con't

Both Cities operate their own power plants containing peaking units, and BWP also operates the Magnolia Power Plant ("MPP"), a baseload unit, on behalf of the Southern California Public Power Authority ("SCPPA"). Participants in MPP include Burbank, Pasadena, and four other municipalities. The Cities operate these power plants to serve their municipal customers. RTCs are required not only to cover anticipated annual emissions, but also to meet resource adequacy needs and prepare for utility-specific operating contingencies, such as grid reliability, increased cycling to support integration of renewables, and potential electrification of the transportation system. Unlike other industrial facilities operating under the RECLAIM program, the Cities' power plants are obligated to operate to serve load. If they are unable to serve load, there may be blackouts with serious adverse economic and other consequences. 3-4

The staff proposal would require a 47% reduction in the NOx RTC allocations for these power plants. The proposed reductions are so severe that insufficient RTCs would remain to cover Pasadena's and MPP's anticipated emissions, not to mention RTCs needed for resource adequacy and utility-specific operating contingencies. Pasadena and MPP may need to purchase additional RTCs to cover the shortfall. If these additional RTCs are prohibitively expensive or unavailable, then the Cities may be forced to curtail the output from these facilities in order to remain in compliance with the RECLAIM program. 3-5

One possible consequence of a curtailment of output from the Cities' facilities is that other facilities may generate replacement power. These facilities may be located either inside or outside of the South Coast Air Basin. Wherever they are located, these other facilities are unlikely to have emission rates as low as the emission rates from the Cities' own facilities. The increased emissions from these other facilities, and their potential adverse impacts, should be assessed in the Final PEA. 3-6

For example, replacement power may be generated by facilities that are located in the South Coast Air Basin that are not included in the RECLAIM program or that are included in the program but are not subject to the NOx shave proposal, such as certain co-generation facilities. The emissions would be generated in locations different from the locations of the Cities' facilities, and there are likely to be more emissions than would be generated by the Cities' own well-controlled units. These emissions and their potential adverse impacts, including their impacts on local receptors, should be assessed. These adverse impacts may trigger environmental justice concerns. 3-7

Replacement power may also be generated by facilities that are not located in the South Coast Air Basin. It is possible, for example, that replacement power may be generated by coal-fired units in other states. The potential adverse impacts of these emissions should be assessed. 3-8