SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Preliminary Draft Staff Report
Proposed Rule 1179.1 – NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

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EXECUTIVE SUMMARY

Publicly owned treatment works (POTWs) are facilities that treat municipal wastewater. A POTW is defined as a wastewater treatment or reclamation plant, either owned or operated by a public entity, including all operations within the boundaries of the wastewater or sludge treatment plant. POTWs treat sewage water with a multi-stage process, which includes anaerobic digestion where organic solids are broken down by microorganisms, before discharging water from the facility. This process produces a byproduct called digester gas, a form of biogas. Digester gas differs from other process gases because of the specific contaminants found in wastewater. Digester gas is used to fuel combustion equipment that provides heat or power for processes within the POTW.

During the rulemaking for the December 2018 amendments for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146), Rule 1146.1 - Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146.1), and Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2), the South Coast AQMD received comments describing the unique challenges faced by POTWs associated with digester gas and how POTWs provide essential public services. Staff recommended to separate provisions for combustion equipment at POTWs (and at landfills, which face similar challenges and will be subject to a separate rulemaking). Proposed Rule 1179.1 - NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (PR 1179.1) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for combustion equipment located at POTWs using digester gas and contain provisions applicable to POTWs in one rule.

A total of ninety-three biogas fueled boilers, turbines, and engines, at thirty-one facilities will be affected by PR 1179.1. Oxides of nitrogen (NOx) emission limitations are contained in PR 1179.1 for applicable equipment categories. However, turbines greater than or equal to 0.3 MW are the only equipment category required by PR 1179.1 to meet lower emission limits. Boilers, turbines less than 0.3 MW, and engines will be subject to the same NOx emission limitations contained in current applicable source-specific rules. Equipment not subject to source-specific rules will remain subject to the permit limit. The proposed NOx emission limit of 18.8 ppm at 15 percent oxygen on a dry basis for turbines greater than or equal to 0.3 MW will reduce NOx emissions by 0.05 tpd. The cost-effectiveness for turbines to meet 18.8 ppm at rule adoption is $48,600 per ton of NOx reduced.

PR 1179.1 was developed through a public process. Five Working Group meetings were held on: May 2, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and June 4, 2020. Working Group meetings include affected businesses, environmental and community representatives, public agencies, consultants, and other interested parties. The purpose of the Working Group meetings is to discuss details of proposed amendments and to listen to concerns and issues with the objective to build consensus and resolve issues.

In addition, a Public Workshop will be held on July 22, 2020. The purpose of the Public Workshop is to present the proposed rule language to the general public and to stakeholders, as well as to solicit comments.

CHAPTER 1: BACKGROUND

BACKGROUND

Publicly owned treatment works (POTWs) treat municipal wastewater. A POTW is defined as a wastewater treatment or reclamation plant, either owned or operated by a public entity, including all operations within the boundaries of the wastewater or sludge treatment plant. POTWs treat sewage water with a multi-stage process before discharging water from the facility. The treatment process involves anaerobic digestion where organic solids are broken down by microorganisms. This process produces a byproduct called digester gas, a form of biogas. Digester gas differs from other process gases because of the specific contaminants found in wastewater. Digester gas is used to fuel combustion equipment that provides heat or power for processes within the POTW. If a facility produces excess digester gas or does not have equipment that can utilize produced digester gas, the facility is forced to flare the digester gas. It is ideal for facilities to implement projects that beneficially use digester gas, such as combustion equipment or fuel cells.

During the rulemaking for the December 2018 amendments for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146), Rule 1146.1 - Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146.1), and Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2), the South Coast AQMD received comments describing the unique challenges faced by POTWs associated with digester gas and how POTWs provide essential public services. As a result, staff recommended to separate provisions for combustion equipment at POTWs and landfills, as landfills have similar challenges as POTWs. Proposed Rule 1179.1 - NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (PR 1179.1) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for combustion equipment located at POTWs and to contain provisions specific to equipment located at POTWs in one rule. Staff identified some characteristics of POTWs that required consideration throughout the rule development. These unique characteristics include the use of digester gas, the potential impacts of statewide legislation including Senate Bill (SB) 1383, and the financial challenges that public entities may encounter.

Digester Gas

Digester gas at POTWs is primarily produced from solid organic waste in wastewater but can also be produced from food waste. Digester gas produced by the digestion of solid organic waste found in wastewater has a lower Btu content (higher heating value) than that of natural gas. Btu content has been reported in the range of 550-650 Btu/scf for digester gas produced by facilities in the South Coast AQMD, whereas natural gas has a higher heating value of approximately 1050 Btu/scf. Another significant difference between digester gas and natural gas or other conventional fuels is the presence of siloxanes and high levels of undesirable compounds such as hydrogen sulfide (H_2S).

The presence of siloxanes in gas streams can affect combustion processes if not properly maintained. When siloxane compounds are combusted, silicon dioxide is formed. This glass-like compound forms deposits on components of combustion equipment, increasing maintenance, and if not maintained, can damage combustion equipment. Siloxane presence in digester gas streams can also damage post-combustion equipment, specifically, selective catalytic reduction (SCR) units. SCR catalyst functionality is severely hindered by siloxanes. Siloxanes can deactivate the catalyst of the SCR, causing the SCR to be ineffective. To resolve this problem, facilities use a gas cleaning technology to remove siloxanes before combustion. However, inadequate cleaning of the digester gas could cause the facility to change out the SCR catalyst more frequently, increasing operating and maintenance costs.

SB 1383

SB 1383 - Short-Lived Climate Pollutants; Methane Emissions: Dairy and Livestock; Organic Waste: Landfills was approved on September 19, 2016, and is intended to regulate greenhouse gas emissions by requiring food waste to be diverted from landfills and processed elsewhere. POTWs offer an alternative to landfills for accepting food waste. Acceptance of food waste at POTWs varies, with some POTWs currently accepting food waste and possibly increasing acceptance, some that are currently not accepting food waste that have plans to begin accepting food waste, and some that currently do not and do not have plans to accept food waste in the future. POTWs have commented as part of the work for Rule 1118.1 for non-refinery flares that SB1383 may increase use of digester gas. Although it is expected to increase, the impact of large-scale food waste processing at POTWs remains unclear.

Financial Challenges

POTWs experience financial challenges that private industries do not experience. POTW projects are subject to a structured procurement process. New projects require approval from governing bodies which may be by city council, board of directors, or board of county supervisors, for example. Securing the financial means for a project to comply with regulations may be more difficult for an essential public service than for private industry. POTWs are public service providers and do not manufacture products for sale. To recover costs of implementing a control project, POTWs may need to increase utility rates for the consumer. Increased costs for a public utility may be difficult for a POTWs to impose.

REGULATORY HISTORY

Combustion equipment located at POTWs are currently regulated under the following source-specific rules. NOx and CO emissions from boilers, process heaters and steam generators are regulated under Rules 1146, 1146.1, and 1146.2. This series of rules includes emission limits for all fuels, including digester gas. Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134) applied to turbines that were in operation before 1989. The six turbines located at POTWs were not in operation before 1989. Rule 1134 was amended on April 5, 2019 and excluded turbines located at POTWs considering Proposed Rule 1179.1 was in development. Rule 1134 contains emission limits for all fuels, but does not apply to equipment located at POTWs or landfills. NOx, VOC, and CO emissions from engines are regulated under Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (Rule 1110.2). Rule 1110.2 contains emission limits for all gaseous and liquid fuels, including digester gas. Table I lists the combustion equipment located at POTWs and applicable rules.

TABLE I
RULES APPLICABLE TO COMBUSTION EQUIPMENT AT POTWS

Equipment	South Coast AQMD Rule	General Provisions
Boilers >2 MMBtu/hr	Rules 1146 and 1146.1 (NOx and CO)	Natural gas and digester gas emission limits, source testing frequency, CEMS, monitoring, recording, recordkeeping
Boilers ≤ 2 MMBtu/hr	Rules 1146.2 (natural gas only) (NOx) No requirements for boilers ≤ 2 MM Btu/hr using digester gas	Emission limitations for manufactured equipment fired with natural gas, monitoring, recording, recordkeeping
Emergency internal combustion engines	Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion Engines and Other Compression Ignition Engines (Diesel PM)	Operation limitations, emissions standards, fuel and fuel additive requirements, monitoring, recordkeeping, and reporting requirements
Non-emergency internal combustion engines	Rule 1110.2 (NOx, VOC, and CO)	Natural gas and digester gas emission limits, source testing frequency, source testing protocols, CEMS, monitoring, recording, recordkeeping, I&M plan requirements
Non-refinery flares	Rule 1118.1 (NOx, VOC)	Flare gas, including digester gas, emission limits, source testing requirements, monitoring, recording and recordkeeping
Miscellaneous combustion equipment	Rule 1147 (NOx)	Natural gas and digester gas emission limits, source testing requirements, monitoring, recording and recordkeeping
Turbines ≥ 0.3 MW	Currently no source specific rule for turbines ≥ 0.3 MW at POTWs	N/A
Turbines < 0.3 MW	Currently no source specific rule for turbines < 0.3 MW	N/A

AFFECTED FACILITIES AND EQUIPMENT

Based on South Coast AQMD's permit database, there are 31 POTW facilities with equipment subject to PR 1179.1. PR 1179.1 was developed to address digester gas fired combustion equipment located at POTWs that were not assessed in source-specific rules. Table II contains the equipment affected by PR 1179.1.

TABLE II
AFFECTED EQUIPMENT

Equipment Type	Number of Units
Boilers > 2 MMBtu/hr	
Digester gas	7
Dual fuel	26
Boilers ≤ 2 MMBtu/hr	
Digester gas	2
Dual fuel	10
Turbines ≥ 0.3 MW	
Dual fuel	6
Turbines < 0.3 MW	
Digester gas	5
Dual fuel	5
Engines	
Dual fuel	21

Digester gas turbines and digester gas boilers were not assessed in the April 2019 amendments to Rule 1134 (turbines) or the December 2018 amendments to Rules 1146, 1146.2, and 1146.2 (boilers). Rule 1134 does not apply to any turbine located at a POTW and currently turbines located at POTWs are not subject to any rule. Provisions for digester gas and natural gas fired turbines will be contained in PR 1179.1. All natural gas fired equipment will remain subject to source-specific rules, with the exception of turbines greater than or equal to 0.3 MW. Other equipment at POTWs will not be affected by PR 1179.1, with the exception of digester gas engines. Emergency engines, flares, miscellaneous equipment, and most natural gas fired equipment (excluding turbines ≥ 0.3 MW) will be subject to existing source-specific rules and will not be subject to PR 1179.1. Emergency engines are limited to 200 operating hours per year regardless of fuel. Flares located at POTWs were assessed as part of the January 4, 2019 amendments to Rule 1118.1 – Control of Emissions from Non-Refinery Flares (Rule 1118.1). Flares located at POTWs will remain subject to Rule 1118.1. One digester gas dryer was identified and is currently subject to Rule 1147 – NOx Reductions from Miscellaneous Sources (Rule 1147). Rule 1147 is scheduled to be amended after PR 1179.1 and will contain provisions for digester gas and natural gas fired miscellaneous equipment located at POTWs.

Engine Applicability
Initially during the rule development process, staff was proposing to keep engines fired on biogas, which includes digester gas in Rule 1110.2 since the November 2019 amendments confirmed no changes to the NOx, VOC, and CO limits established in the 2012 amendments. During the initial working group meetings, some stakeholders expressed their preference to include engines in PR 1179.1 in order to have one rule that would address all combustion equipment at POTWs. In subsequent working group meetings, staff informed stakeholders that permit revisions, Inspection and Monitoring (I&M) plans would be needed to reflect PR 1179.1 provision references and presented the associated permit revision fees that facilities would incur.

The costs associated with engine permit revisions are higher compared to other combustion equipment because rule references are more detailed in engine permits and engine permits require Inspection and Maintenance (I&M) plans. Since facilities would incur additional permitting costs if engines requirements in Rule 1110.2 were moved to PR 1179.1, staff surveyed all the POTWs with engines to confirm if facilities support including engines in PR 1179.1, despite incurring associated fees.

Based on the survey, seven of the eight POTWs with non-emergency internal combustion engines support including biogas engines in Rule 1179.1 with the understanding of the additional permitting fees. As a result, staff proposes to include only biogas engines in the applicability of PR 1179.1 and natural gas engines will remain applicable to Rule 1110.2. Some stakeholders requested consideration that fees be waived. Staff cannot waive permitting fees, as this would require an amendment to Regulation III. A stakeholder requested that the permit revisions to include engines be in sync with Title V permit renewals to streamline implementation.

PUBLIC PROCESS

The development of PR 1179.1 was conducted through a public process. Five Working Group meetings were held on: May 2, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and June 4, 2020. Working Group meetings include representatives from affected agencies, environmental and community representatives, affected facilities, industry groups, and other interested parties. The purpose of the working group meetings is to discuss rule concepts and listen to public comments concerning the rule, with the objective to build consensus and resolve key issues.

A Public Workshop will be held on July 22, 2020. The purpose of the Public Workshop is to present the proposed rule to the general public and to stakeholders.

Staff has also conducted multiple site visits as part of this rulemaking process and has met with individual facility operators.

CHAPTER 2: BARCT ASSESSMENT

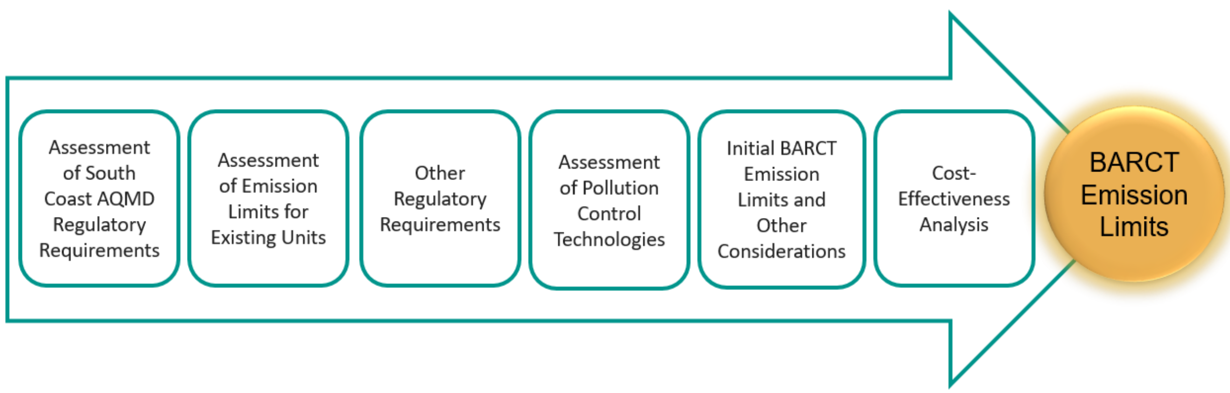
INTRODUCTION

The purpose of a Best Available Retrofit Control Technology (BARCT) assessment is to identify any potential emission reductions from specific equipment or industries and establish an emission limit that is consistent with state law. Under California Health and Safety Code § 40406, BARCT is defined 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."

BARCT assessments are performed periodically for equipment categories to determine if current emission limits are representative of BARCT emission limits. The BARCT assessment process identifies current regulatory requirements for equipment categories established by South Coast AQMD and other air districts. Permit limits and source test data are analyzed to identify the emission levels being achieved with existing technology. Current and emerging technologies are assessed to determine the feasibility of achieving lower NOx emission levels. An initial BARCT emission limit is proposed based the BARCT assessment. Costs are gathered and analyzed to determine the cost for a unit to meet the proposed initial NOx emission limit. A cost-effectiveness calculation is made that considers the cost to meet the initial proposed NOx limit and the reductions that would occur from implementing technology that could meet the proposed limit. A final BARCT emission limit is established that is based on the BARCT assessment, including the cost-effectiveness analysis.

Figure 2-1 – BARCT Assessment Process



BARCT assessments for some equipment at POTWs were not conducted for certain biogas equipment during recent source specific rulemakings. The equipment that was assessed for PR 1179.1 includes digester gas fired boilers and turbines. Digester gas engines underwent a BARCT analysis under Rule 1110.2 and most of those engines had effective dates beginning in January 1, 2017, therefore, a BARCT assessment for digester gas engines was not conducted for this rulemaking.

BARCT ANALYSIS APPROACH

Boilers ≤ 2 MMBtu/hr

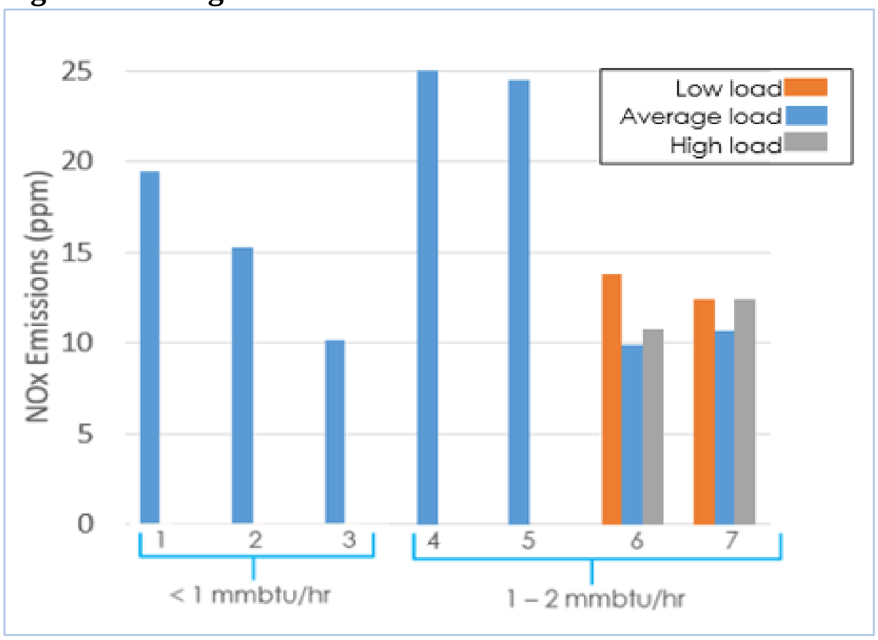
Assessment of South Coast AQMD Regulatory Requirements

There are 12 boilers ≤ 2 MMBtu/hr fired on digester gas within South Coast AQMD jurisdiction (2 digester gas, 10 dual fuel). These units are subject to individual permit limits. The permits limits for existing units are 30 ppm at 3 percent oxygen on a dry basis with the exception of 2 boilers with a permit limit of 6 lbs/day and 2 boilers without a permit limit. South Coast AQMD has no rule requirement for boilers ≤ 2 MMBtu/hr that fire digester gas. Rule 1146.2 prohibits manufacturing for use or offering for sale for use burners ≤ 2 MMBtu/hr fired with natural gas that emit more than 30 ppm of NOx at 3 percent oxygen on a dry basis. Although natural gas units covered by Rule 1146.2 are exempt from permitting requirements, all digester gas units have South Coast AQMD permits.

Assessment of Emission Limits for Existing Equipment

Source tests were obtained for 7 of the 12 boilers and results ranged from 10.2 ppm to 25.0 ppm at 3 percent oxygen on a dry basis. Units ≤ 1 MMBtu/hr all had source test results of less than 20 ppm at 3 percent oxygen on a dry basis. Figure 2-2 shows the source test results obtained for boilers ≤ 2 MMBtu/hr.

Figure 2-2 – Digester Gas Boiler Source Test Results



**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis*

Other Regulatory Requirements

San Joaquin Valley Air Pollution Control District (SJVAPCD) and Sacramento Metropolitan Air Quality Management District (SMAQMD) have similar requirements that prohibit the distribution or installation of any burner not meeting the rule requirement; however, SJVAPCD and SMAQMD restrictions are not limited to natural gas only fired units. SJVAPCD's Rule 4308 limits NOx emissions from burners > 0.4 MMBtu/hr and less than 2.0 MMBtu/hr to 30 ppm at 3 percent oxygen on a dry basis, ≥ 0.075 and less than 0.4 MMBtu/hr to 77 ppm at 3 percent oxygen on a dry basis. SMAQMD's Rule 411 limits units > 1 MMBtu/hr and less than 5 MMBtu/hr to 30 ppm at 3 percent oxygen on a dry basis, and units 0.4 MMBtu/hr and ≤ 1 MMBtu/hr to 20 ppm at 3 percent oxygen on a dry basis.

Assessment of Pollution Control Technologies
Staff discussed with one supplier the availability of 12 ppm at 3 percent oxygen on a dry basis low NOx burners for boilers ≤ 2 MMBtu/hr. The supplier stated that 12 ppm at 3 percent oxygen on a dry basis burners are available in sizes ≥ 1 MMBtu/hr and that the 12 ppm NOx emission level is guaranteed. Staff did not receive information from suppliers regarding achievable emission levels for boilers < 1 MMBtu/hr. A supplier informed staff that retrofitting low NOx burners for boilers < 1 MMBtu/hr could be challenging due to the smaller, more limiting, dimensions of a small boiler and could not guarantee 12 ppm at 3 percent oxygen on a dry basis for boilers < 1 MMBtu/hr. Source tests indicate that existing burners for boilers < 1 MMBtu/hr are meeting 20 ppm at 3 percent oxygen on a dry basis.

Initial BARCT Emission Limits and Other Considerations
Based on the information from one supplier and source test data, staff finds that a NOx emission limit of 12 ppm at 3 percent oxygen on a dry basis for boilers 1 – 2 MMBtu/hr and 20 ppm at 3 percent oxygen on a dry basis for boilers < 1 MMBtu/hr is feasible. The total emission reductions for boilers ≤ 2 MMBtu/hr would be 0.0005 tpd. Because of the small emission reductions and the concern that facilities have with meeting lower limits, staff is proposing a 30 ppm at 3 percent oxygen on a dry basis emission limit on all boilers ≤ 2 MMBtu/hr. There are 2 boilers with an emission limit of 6 lbs/day and 2 boilers that without a permitted emission limit. All other boilers ≤ 2 MMBtu/hr are permitted at 30 ppm at 3 percent oxygen on a dry basis.

TABLE III
INITIAL NOX EMISSION LIMITS FOR BOILERS ≤ 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption
Boilers ≤ 2 MMBtu/hr	30 ppm*

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*

Cost-Effectiveness Analysis
The units affected by the proposed emission limit are not permitted with a NOx concentration emission limit. Staff could not determine emission reductions from these units and did not conduct a cost-effectiveness calculation.

BARCT Emission Limits
Staff proposes that units without permitted NOx concentration limits will be subject to the emission limit upon a burner or boiler replacement. The following table provides the proposed BARCT emission limits for boilers ≤ 2 MMBtu/hr.

TABLE IV
PROPOSED BARCT EMISSION LIMITS FOR BOILERS ≤ 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption*	Limit Upon Burner or Boiler Replacement*
Boilers ≤ 2 MMBtu/hr	Permit Limit	30 ppm

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*

Boilers > 2 MMBtu/hr

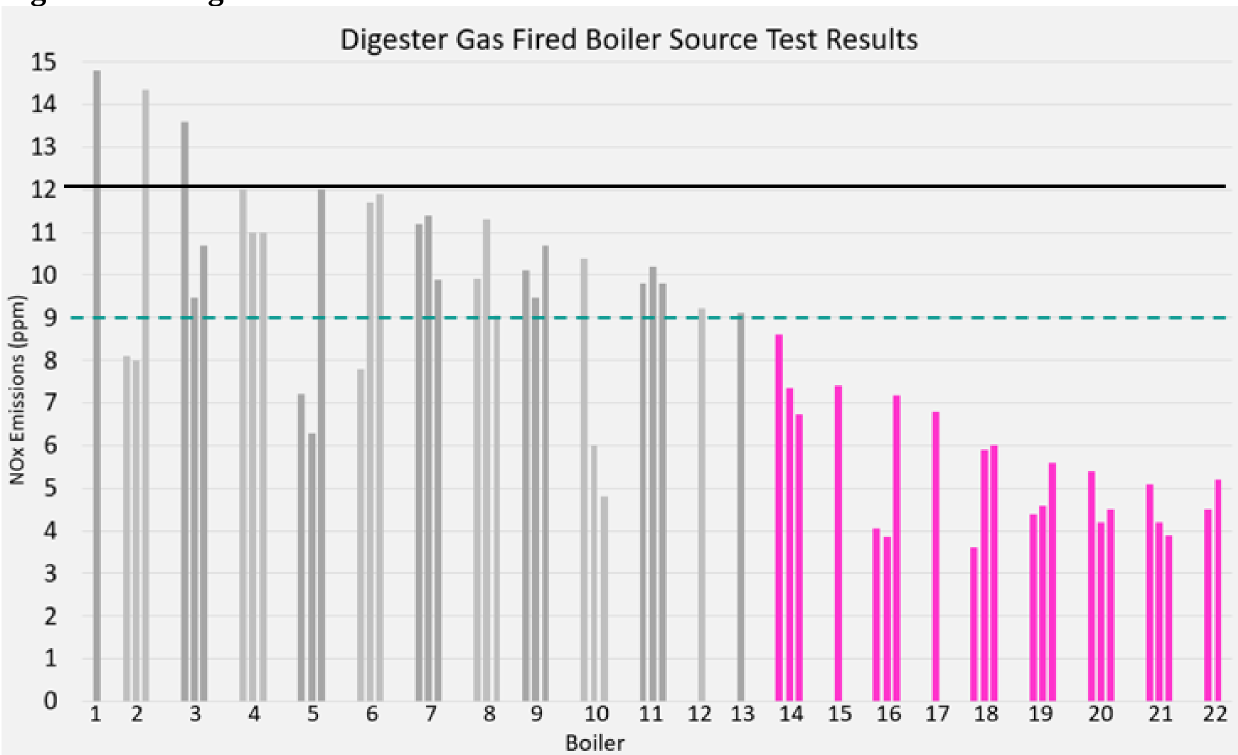
Assessment of South Coast AQMD Regulatory Requirements

South Coast AQMD's Rules 1146 and 1146.1 require boilers > 2 MMBtu/hr meet 15 ppm at 3 percent oxygen on a dry basis when firing digester gas and 9 ppm at 3 percent oxygen on a dry basis when firing natural gas. Rules 1146 and 1146.1 were recently amended in December 2018 and a BARCT assessment was conducted for natural gas boilers. The amendments require certain natural gas boilers to meet 7 ppm at 3 percent oxygen on a dry basis, however, natural gas boilers located at municipal sanitation service facilities are subject to 9 ppm at 3 percent oxygen on a dry basis. Co-fired boilers remained subject to a weighted average emission limit when firing more than an approve percent of natural gas.

Assessment of Emission Limits for Existing Units

Source test results for boilers >2 MMBtu/hr in South Coast AQMD jurisdiction firing 100 percent digester gas indicate that 9 ppm at 3 percent oxygen on a dry basis is achievable. Source tests were obtained for 22 out of 33 boilers permitted to fire digester gas. Twenty-six boilers are dual fuel and have the ability to separately fire digester gas and natural gas, and 7 are digester gas fired only. Source tests contained results for boilers firing low, mid, and high loads with the exception of 5 boilers firing mid load and one boiler firing low and average loads. All boilers in Figure 2-3 meet the 15 ppm at 3 percent oxygen on a dry basis emission limit. Nine boilers source tested below 9 ppm at 3 percent oxygen on a dry basis at all loads (highlighted). Results are displayed in order of low, mid, and high load in Figure 2-3.

Figure 2-3 – Digester Gas Fired Boiler Source Test Results



**All emission results in parts per million (ppm) are referenced at 3 percent oxygen, on a dry basis.*

Monthly periodic monitoring is required by Rules 1146 and 1146.1. Periodic monitoring results were also analyzed to determine if source tests are representative of normal boiler performance. Complete sets of monthly monitoring data were obtained for six boilers. Staff determined that source results were representative of average emission levels. For example, two boilers that source tested below 9 ppm at 3 percent oxygen on a dry basis had periodic monitoring test results below 9 ppm at 3 percent oxygen on a dry basis in more than 90 percent of the tests. One boiler exceeded 9 ppm at 3 percent oxygen on a dry basis twice over the course of five years. Another boiler exceeded 9 ppm at 3 percent oxygen on a dry basis three times in five years.

Other Regulatory Requirements

Two districts have emission limits more stringent than South Coast AQMD for digester gas boilers. SJVAPCD currently has a permitted boiler that fires digester gas. The boiler complies with SJVAPCD's Rule 4320 limit of 9 ppm at 3 percent oxygen on a dry basis. The boiler is a dual fuel and 16.7 MMBtu/hr. The boiler recently source tested at 7.9 ppm at 3 percent oxygen on a dry basis while firing 100 percent digester gas. Stakeholders commented that SJVAPD's allowed tuning practices prior to source testing may allow for lower emission results and/or rule limits. South Coast AQMD requires that a boiler must operate at least 250 hours or 30 days subsequent to tuning or servicing. Staff at SJVAPCD informed South Coast AQMD that a boiler must be operating at least 2 hours subsequent to tuning. Staff was unable to locate a protocol that specifies the requirements for source testing. Despite possible different source test protocols, results for digester gas fired boilers in South Coast AQMD also reflect NOx emissions levels < 9 ppm at 3 percent oxygen on a dry basis.

SMAQMD's Rule 411 requires that boilers > 20 MMBtu/hr meet 9 ppm at 3 percent oxygen on a dry basis, boilers ≥ 5-20 MMBtu/hr meet 15 ppm at 3 percent oxygen on a dry basis, and boilers ≥ 1 – 5 meet 30 ppm at 3 percent oxygen on a dry basis. The limits apply to boilers that fire any fuel which is a gas at standard conditions. Rule 411 does not specify a limit for digester gas. Units ≥ 5 MMBtu/hr that fire landfill gas have a limit of 15 ppm at 3 percent oxygen on a dry basis. SJVAPCD's Rule 4320 specifies limits for boilers ≥ 2 – 5 MMBtu/hr that fire gaseous fuel, where "gaseous fuel" is defined as any fuel that is a fuel at which is a gas at standard conditions. The limits are 12 ppm (atmospheric) and 9 ppm (non-atmospheric), at 3 percent oxygen on a dry basis. Boilers > 5 MMBtu/hr that fire more than 50 percent by volume PUC quality gas are subject to an emission limit of 9 ppm at 3 percent oxygen on a dry basis.

Assessment of Pollution Control Technologies

Thermal NOx is the largest contributor to NOx emissions from boilers and is formed by high flame temperatures. Different control technologies exist that reduce NOx emissions from boilers. Low NOx burners and flue gas recirculation reduce the formation of thermal NOx at the combustion zone and SCR removes NOx post-combustion. Low NOx burners control the air-fuel mixture during combustion and modify the shape of the flame or number of flames to reduce NOx formation and maintain efficiency. Flue gas recirculation is a method of NOx control that returns hot flue gas to the combustion air stream to lower flame temperature. Low NOx burners are currently used on all boilers that fire digester gas in South Coast AQMD. Some boilers utilize flue gas recirculation systems alone or with an oxygen trim system. SCR is not necessary to meet the current limit of 15 ppm and no facilities are using SCR to limit NOx emissions on boilers.

One stakeholder commented that their boilers experience flame-out due to siloxane build up. This facility has opted to treat the gas prior to combustion to resolve the issue. Stakeholders also commented on the instability of NOx emission levels while firing digester gas with low-NOx burners. One facility commented that holes are created in their mesh burner screens, possibly due to digester gas combustion hot spots.

Staff discussed the issues brought forth by stakeholders with three burner suppliers. Suppliers stated that unstable NOx emissions can result from fluctuations in the high heating value (HHV) of the digester gas, weather changes, load changes, and contaminants.

Staff was informed that oxygen trim systems are beneficial in managing fluctuations in HHV and can tolerate fluctuations of ±100 Btu/scf. Fluctuations of ±50 Btu/scf in HHV should not cause unstable NOx emissions. Changes in weather such as temperature swings and humidity swings can lead to emission instability and would require more frequent tuning. Weather changes can result in 3 ppm – 4 ppm, at 3 percent oxygen on a dry basis swings in NOx emissions and the recommended tuning frequency is every 3 – 6 six months depending on the target NOx emission levels. Load swings are managed with the turndown ratio of the burner. A typical low NOx burner has a turndown ratio of 4:1. A burner with a small turndown ratio offers less flexibility to manage load swings.

Contaminants can damage burner screens that may result in unstable NOx emissions. Corrosive contaminants such as H_2S can corrode screens and siloxanes can clog screens leading to hotspots that may cause holes to form in the screen. If gas is untreated prior to combustion, burners need to be cleaned every 3 – 6 months depending on the level of contaminants. To avoid damage to burner screens, gas should be adequately treated to remove contaminants prior to combustion. Ambient temperature is another factor that may contribute to holes forming in burner screens as holes may form from air expansion. Oxygen trim systems can be used to manage the amount of air in the fuel to avoid complications with air expansion. Woven screens are another option for managing fluctuations in air volume.

One supplier stated that achieving emission levels of 7 ppm – 9 ppm, at 3 percent oxygen on a dry basis is possible with proper tuning and possibly an oxygen trim system or flue gas recirculation system that optimizes the air-to-fuel ratio. However, this supplier could not guarantee emission levels at 9 ppm at 3 percent oxygen on a dry basis due to the varying HHV in digester gas.

Initial BARCT Emission Limits and Other Considerations

Staff is proposed an initial NOx emission limit of 12 ppm at 3 percent oxygen on a dry basis for boilers greater than 2 MMBtu/hr. Earlier in the rule development staff proposed an initial NOx emission limit of 9 ppm at 3 percent oxygen on a dry basis based on discussions with suppliers and emission test results. Staff reached out to stakeholders and followed up with suppliers regarding the proposed NOx emission limit. Stakeholders expressed their concern about meeting 9 ppm at 3 percent oxygen on a dry basis consistently and stated that 9 ppm at 3 percent oxygen on a dry basis is achievable, but it would require operators to tune the boiler more frequently, impacting resources at the facility.

Two other suppliers guaranteed NOx emission levels of <12 ppm at 3 percent oxygen on a dry basis for burner replacements. One of the suppliers stated that 9 ppm at 3 percent oxygen on a dry basis burners would be available in the next few years. Stakeholders expressed their reluctance to rely on supplier guarantees. However, in staff's analysis of source test results for boilers > 2 MMBtu/hr, 19 out of 22 boilers (Figure 2-3) met 12 ppm at 3 percent oxygen on a dry basis for all loads required by the source tests. The suppliers claiming a guarantee of 12 ppm at 3 percent oxygen on a dry basis do not manufacture the burners that source tested above 12 ppm at 3 percent oxygen on a dry basis. Based on the information from emission tests results and the emission levels that suppliers will guarantee for new burners, staff proposed an emission limit of 12 ppm at 3 percent oxygen on a dry basis.

Cost-Effectiveness Analysis

Staff conducted a cost-effectiveness analysis to retrofit boilers with burners that can meet 12 ppm at 3 percent oxygen on a dry basis. The average cost-effectiveness to meet 12 ppm at 3 percent oxygen on a dry basis is > $50,000 per ton of NOx reduced to require facilities to replace burners before the time that the facility would regularly replace the equipment because emission reductions are relatively low.

BARCT Emission Limits
Staff is proposing the current NOx emission limit of 15 ppm at 3 percent oxygen on a dry basis for boilers < 2 MMBtu/hr. Replacements and new units will be required to meet BACT emission levels. The following table provides the proposed BARCT emission limits for boilers > 2 MMBtu/hr.

TABLE V
PROPOSED BARCT EMISSION LIMITS FOR BOILERS > 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption*	Limit Upon Burner or Boiler Replacement
Boilers > 2 MMBtu/hr	15 ppm	BACT Emission Level

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*

Turbines < 0.3 MW
There are 10 turbines < 0.3 MW located at two POTW facilities within South Coast AQMD jurisdiction. Five are exempt from permitting and do not have emission limits, while five are not yet commissioned and have been permitted at 9 ppm at 15 percent oxygen on a dry basis.

Assessment of South Coast AQMD Regulatory Requirements
There is currently no South Coast AQMD rule that establishes a NOx limit for turbines < 0.3 MW at South Coast AQMD. Rule 219 allows microturbines ≤ 3.5 MMBtu/hr (total output < 2 MW) to be exempt from permitting provided that a filing pursuant to Rule 222 is submitted and the microturbines were in operation prior to May 3, 2013 or the microturbines were certified by the state of California at the time of manufacture. Staff is amending Rule 1147 – NOx Reductions from Miscellaneous Sources that will establish provisions for natural gas fired microturbines.

Assessment of Emission Limits for Existing Units
The five turbines currently operating are not subject to as emission limit. One source test was obtained for one turbine. The turbine source tested at 1.25 ppm at 15 percent oxygen on a dry basis with 100 percent digester gas.

Other Regulatory Requirements
Staff did not identify NOx emission limits for turbines < 0.3 MW in another air district's rules. The State of California has issued requirements for microturbines that are exempt from any District requirements. Such microturbines must comply with CARB's Distributed Generation regulations standards, which are near 2 ppm at 15 percent oxygen on a dry basis or NOx (0.07 lbs/MW-hr), and must be certified, if manufactured after January 1, 2013. However, existing unpermitted units are certified and subject to previous CARB Executive Orders of 9 ppm at 15 percent oxygen on a dry basis NOx after January 1, 2008 and before January 1, 2013 (date of manufacture).

Assessment of Pollution Control Technologies
Microturbines use a lean pre-mix to limit NOx emissions without post combustion control technology such as SCR. SCR is not suitable for microturbines because of the low exhaust temperature and SCR's requirement for high exhaust temperature to activate catalysts. One

microturbine supplier guarantees 9 ppm at 15 percent oxygen on a dry basis for microturbines that fire digester gas or a blend of digester gas and natural gas. The supplier stated that 9 ppm at 15 percent oxygen on a dry basis can be met over a range of loads, but high load is suggested to consistently meet emission levels. Proper gas treatment and maintenance is imperative to meet the target emission levels.

Initial BARCT Emission Limits and Other Considerations

Staff is proposing a NOx emission limit of 9 ppm at 15 percent oxygen on a dry basis based on supplier discussions and current permitted levels for all turbines < 0.3 MW with the exception of turbines that are permit exempt and were installed prior to May 3, 2013. There is insufficient source test information to determine if the existing turbines that are permit exempt can meet 9 ppm at 15 percent oxygen on a dry basis.

TABLE VI
INITIAL NOX EMISSION LIMITS FOR TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption*
Turbines < 0.3 MW installed prior to May 3, 2013	N/A
Turbines < 0.3 MW	9 ppm

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Cost-Effectiveness Analysis

Five of the 10 existing turbines < 0.3 MW are permitted at the proposed initial NOx limit and no cost-effectiveness analysis was conducted. The other five turbines will not be affected by the proposed emission limit until unit replacement. No incremental costs are assumed to replace units with units that can meet 9 ppm at 15 percent oxygen on a dry basis. A cost-effectiveness analysis was not conducted for units that will meet the emission limit upon replacement.

BARCT Emission Limits

The following table provides the proposed BARCT emission limits for turbines < 0.3 MW that fire digester gas or a digester gas blend.

TABLE VII
PROPOSED BARCT EMISSION LIMITS FOR TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit Upon Turbine Replacement*
Turbines < 0.3 MW installed prior to May 3, 2013	N/A	9 ppm
Turbines < 0.3 MW	9 ppm	9 ppm

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Turbines ≥ 0.3 MW

Based on the South Coast AQMD's permit database, there are six combined cycle turbines located at two POTWs that fire either digester gas only or a digester gas blend. One facility has three 11.35 MW turbines that fire a blend of digester gas and natural gas (60 percent digester gas, 40 percent natural gas). These turbines currently use SCR and the digester gas is treated to remove siloxanes prior to combustion. The other facility has three 9.9 MW turbines that fire digester gas but are permitted to blend up to 40 percent natural gas. This facility does not have SCR and does not treat the digester gas prior to combustion.

Assessment of South Coast AQMD Regulatory Requirements

South Coast AQMD has no rule for turbines located at a POTW. South Coast AQMD Rule 1134 which applies to stationary gas turbines, 0.3 MW and larger, excludes turbines located at POTW facilities.

Assessment of Emission Limits for Existing Units

The turbines are subject to South Coast AQMD permit limits. The turbines have NOx concentration limits of 18.8 ppm and 25 ppm, at 15 percent oxygen on a dry basis. Table VIII summarizes the unit sizes, type of emission controls, and permitted NOx concentration limit, at each facility.

TABLE VIII
CURRENT PERMIT LIMITS FOR DIGESTER GAS TURBINES

Facility	Number of Units	Unit Size (MW)	Emission Controls	Permit Limit (ppmv at 15% O2)
1	3	9.9	Water injection only	25
2	3	11.35	SCR	18.8

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Staff analyzed recent source test results for the six turbines. Two of the three turbines permitted at 18.8 ppm source tested at 14.7 ppm and 15.9 ppm, at 15 percent oxygen on a dry basis, when firing digester gas and 13 ppm and 14.3 ppm, at 15 percent oxygen on a dry basis, when firing a 60/40 blend of digester gas/natural gas. Source test results for the third turbine were unavailable. The three turbines permitted at 25 ppm source tested between 20.7 ppm – 21.3 ppm, at 15 percent oxygen on a dry basis.

SJVAPCD has permitted two turbines located at a POTW that fired a blend of digester gas (~70 percent) and natural gas (~30 percent) at 5 ppm at 15 percent oxygen on a dry basis. The operator of the facility informed staff that the facility was using water injection to meet a previous 25 ppm at 15 percent oxygen on a dry basis NOx rule limit. The facility discontinued water injection and implemented gas treatment and SCR to meet the new 5 ppm at 15 percent oxygen on a dry basis rule limit. Source test results were obtained prior to the decommissioning of the turbines. Seven source tests from the last five years of operation were obtained for the turbines. The results ranged from 2.5 ppm – 3.9 ppm, at 15 percent oxygen on a dry basis. The turbines were in operation from 2004 – 2016.

Other Regulatory Requirements
Staff identified NOx emission limits for digester gas turbines in other air districts' rules. Requirements at SMAQMD and SJVAPCD for digester gas turbines are as stringent or more stringent than South Coast AQMD's permit limits.

SJVAPCD's Rule 4703 requires combined cycle turbines > 10 MW to meet a NOx limit of 3 ppm or 5 ppm, at 15 percent oxygen on a dry basis, depending on the implementation schedule. The emission limits apply to turbines using gas fuel that includes digester gas. Units meeting 3 ppm at 15 percent oxygen on a dry basis had a longer compliance timeframe. Turbines between 3 MW – 10 MW that operate 877 hours per year or more are subject to a NOx concentration limit of 5 ppm at 15 percent oxygen on a dry basis.

SMAQMD's Rule 413 requires turbines ≥ 10 MW with SCR that operate 877 hours per year or more to meet 9 ppm at 15% oxygen on a dry basis for turbines that use gaseous fuel that includes any fuel that is a gas at standard conditions. Turbines ≥ 2.9 – < 10 MW are subject to a 25 ppm at 15 percent oxygen on a dry basis NOx concentration limit. Four turbines are permitted by SMAQMD that fire a blend of digester gas and natural gas and are permitted at 2.5 ppm and 2.0 ppm, at 15% oxygen on a dry basis. However, these turbines used a blend of only 2 percent digester gas. SCR is used for NOx control on the turbines permitted at 2.5 ppm and SCR along with a dry low NOx combustion system is used for the turbines permitted at 2.0 ppm. Staff concluded that the turbines permitted by SMAQMD do not provide a comparison to the turbines in South Coast AQMD for achievable NOx emission levels from digester gas turbines because a) the dry low NOx combustion systems used to meet 2 ppm are not compatible with turbines that use fuel blend with a lower Wobbe index (not to pipeline quality gas specifications); and, b) the percentage of digester gas in the fuel blend is much lower than the percentages used in the fuel for the turbines at South Coast AQMD.

Assessment of Pollution Control Technologies
Staff assessed the feasibility of certain control technologies to meet specific NOx emission levels. Implemented control technologies were evaluated by performance data and discussions with facility operators and equipment suppliers. Staff visited POTW sites to learn from equipment operators about their experiences with combustion and control equipment.

Water or Steam Injection
Water or steam injection is a common control system built into turbines that reduces thermal NOx formation by lowering the combustion zone temperature. Water injection requires demineralized water that is costly and less convenient than utility water. Storage sites and delivery are required for use of demineralized water. Utilizing water injection is undesirable due to the potential for imprecise water application that can lead to hotspots, causing NOx formation, increased fuel usage and increased carbon monoxide (CO) emissions, along with the deterioration of turbine parts from water abrasion. The facility with turbines permitted at 25 ppm at 15 percent oxygen on a dry basis informed staff that their turbines can meet 18.8 ppm at 15 percent oxygen on a dry basis with increased water injection.

Dry Low Emissions (DLE)

Dry low emission (DLE) or lean pre-mixed technology is a combustion system that does not use water or steam to reduce thermal NOx. DLE systems have a mechanism to pre-mix the air and fuel to create a lean mixture that allows combustion at a lower temperature. Lean pre-mixed combustion systems minimize local hotspots that produce elevated combustion temperatures, forming thermal NOx. One turbine supplier informed staff that its DLE systems are not compatible with digester gas due to the low Wobbe index of digester gas. The DLE system is limited to fuels with a Wobbe index number range of 1100-1340, whereas the Wobbe index range of digester gas is much lower, at approximately 600. Although increasing the amount of natural gas in the fuel blend would increase the Wobbe index number, a 60/40 blend of digester gas/natural gas would not be compatible with the dry low NOx combustion system. Furthermore, DLE combustion systems are an intrinsic part of a turbine's design and not considered available for retrofit on existing turbines.

Selective Catalytic Reduction (SCR)

SCR is a primary post-combustion technology for NOx reduction and is capable of reducing 90-95 percent of post combustion NOx. SCR reduces NOx to nitrogen and water through a reaction with ammonia and oxygen. Catalyst is used for the reaction and is negatively affected by siloxane contamination in biogas. Siloxane containing biogas requires gas treatment to maintain SCR effectiveness. SCR is a post-combustion NOx control technology and may be used in combination with combustion alteration NOx control technologies, such as dry low NOx combustion systems and low NOx burners. SCR requires on-site storage of ammonia or urea and the technology carries the potential of creating unwanted stack ammonia emissions (ammonia slip) from unreacted ammonia. Catalysts are available that reduce ammonia slip emissions but were not evaluated as part of the SCR technology assessment. A limiting factor for SCR applications is the technology's requirement high operating temperature. Exhaust gas temperatures typically need to be between 400F – 800F. SCR is not suitable for combustion equipment with low exhaust temperatures. SCR is used on a variety of equipment including turbines, engines, and boilers, but must be accompanied with an adequate fuel gas treatment system (FGTS). One equipment supplier stated that siloxane levels need to be as low as 25 ppb to guarantee SCR performance for any length of time. The gas treatment systems currently used at POTWs and landfills have been designed to remove siloxanes to levels between 75 ppb – 500 ppb. These gas treatment systems are currently used in conjunction with SCR. Removal of siloxanes prior to combustion is necessary for proper SCR performance. Inadequate siloxane removal can quickly deactivate the SCR catalyst and require frequent catalyst replacements.

Within South Coast AQMD, SCR is currently used at a POTW with three digester gas turbines equipped with SCR. The which was permitted in 2017 concluded that the turbine's uncontrolled NOx emissions of 213 ppm at 15 percent oxygen on a dry basis can be reduced to 18.75 ppm at 15 percent oxygen on a dry basis with SCR and the SCR could provide 91.2 percent NOx reduction. The use of SCR at this facility requires a FGTS to remove siloxanes and H_2S contaminants that the facility implemented with the project. Two turbines have source tested at 15.9 ppm and 14.7 ppm, at 15 percent oxygen on a dry basis, when firing 100 percent digester gas. A source result for the third turbine was unavailable. It is expected that turbines equipped with SCR firing digester gas can achieve reductions consistent with the reductions that this POTW is achieving with SCR on the turbines.

SCR was also used at a POTW within SJVAPCD. SCR was used on two turbines that had inlet NOx emission levels of 25 ppm at 15 percent oxygen on a dry basis at minimum. The turbines source tested as low as 2.5 ppm at 15 percent oxygen on a dry basis, indicating that the SCRs were capable of achieving 90 percent NOx reduction when operated with digester gas turbines.

Fuel Gas Treatment Systems

FGTS remove undesired compounds from non-conventional fuels, such as digester gas. Digester gas produced at wastewater treatment plants contain siloxane and H_2S contaminants. It is imperative that digester gas is treated for proper combustion and post-combustion equipment function. While some equipment is less impaired by siloxanes and other contaminants, some level of gas treatment is usually required for a combustion process that uses digester gas. There are three prominent FGTS types that utilize different techniques for removing contaminants – consumable media type, regenerative media type and a chiller/adsorption type. A FGTS may consists of one or a more removal system types.

The effectiveness of contaminant adsorption depends on the media type and the contaminants in the gas stream. The three most common types of media that are used in the South Coast AQMD at landfills and POTWs are activated carbon, molecular sieve, and silica gel. Each media type has its advantages. Activated carbon is a versatile adsorbent that is highly porous and is suitable to adsorb organic molecules. A molecular sieve has pores of uniform size and is capable of performing selective removal of contaminants at low concentrations. Silica gel is a shapeless and porous adsorbent that has a greater capacity than activated carbon to adsorb siloxanes and has a high affinity for water that aids in moisture removal.

Consumable media type systems are commonly used with activated carbon. This type of removal system requires saturated media to be changed out. Spent media is disposed and new media is reintroduced. Installment and maintenance costs are typically less than regenerative and chiller media systems because the equipment is less complex than consumable media systems, but more frequent media removal and disposal can result in significant operating costs to the facility.

Regenerative media systems are commonly used with media such as molecular sieve, silica gel, clay and zeolite. These systems consist of at least two media canisters. One batch of media processes gas while the other regenerates by purging with hot air. Regenerative media types require smaller canisters and less media in comparison to consumable media systems. Regenerative media function can be enhanced by applying polymeric resins. Polymerics resins can increase service life, increase adsorbent capacity, and remove contaminants quicker and at a lower temperature when regenerating.

Chiller/adsorption or refrigeration systems remove contaminants by reducing the temperature of the digester gas to condense out moisture and contaminants. These systems have been used in combination with consumable media systems at landfills. The consumable media system serves as a polishing stage to remove trace amounts of siloxanes or other contaminants. Wastewater treatment and landfill facilities have reported 50 percent removal efficiency of siloxanes and 32 percent long-term removal efficiency of siloxanes, with refrigeration. Bench-scale studies have shown 95 percent removal of siloxanes with advanced refrigeration.[1]

Within South Coast AQMD, five facilities use FGTS systems and treat gas prior to combustion in twelve digester gas engines that are equipped with SCR for post-combustion control. One facility uses a FGTS prior to combustion in three turbines. At other POTWs, FGTS systems are also used to treat digester gas prior to entering a fuel cell. If low siloxane levels are not maintained, media replacement will be more frequent raising costs associated with fuel gas treatment systems.

New Turbines

Newer gas turbines are capable of low NOx emission levels, between 4 ppm – 25 ppm when firing natural gas without SCR. Achievable NOx emission levels while firing digester gas vary and depend on the constituents of the digester gas. DLE systems are incompatible with digester gas due to the low Wobbe index number for digester gas, but there is one commercially available turbine ≥ 0.3 MW that incorporates a DLE system compatible with biogas and a recuperator. The manufacturer of this turbine guarantees 15 ppm at 15 percent oxygen on a dry basis for landfill gas and 25 ppm at 15 percent oxygen on a dry basis for digester gas. The widespread application of this turbine is limited due to its maximum output rating of 4.6 MW.

Two other turbine manufacturers have estimated emission levels of 15 ppm and 25 ppm when firing digester gas for larger sized turbines, in the 10 MW range. One of the turbine suppliers stated that they can guarantee emissions levels of 15 ppm and 25 ppm, at 15 percent oxygen on a dry basis, depending on the model, for turbines without SCR fueled with digester gas.

Within landfills and POTWs in California, eleven turbines operate without SCR and are fueled with either landfill gas or digester gas. These are the only known turbines in operation with a DLE system that are compatible with biogas. Ten of these turbines are located at landfills and one is located at a POTW. Digester gas is treated is prior to combustion in the turbines and SCR is not utilized. All turbines located at the landfills source tested between 3.1 ppm – 7.6 ppm, at 15 percent oxygen on a dry basis. Some of the turbines are permitted at 12.5 ppm at 15 percent oxygen on a dry basis, while others are permitted at 25 ppm at 15 percent oxygen on a dry basis.

Staff obtained additional information from a POTW that operates an identical turbine to the turbines operated at landfills not using SCR. The turbine located at the POTW achieved NOx emission levels consistent with the landfill turbines. The operator of the POTW facility provided monthly emission tests results for years 2018 and 2019. Results ranged from 3.7 ppm – 8.1 ppm, at 15 percent oxygen on a dry basis (2018) and 4.4 ppm – 7.7 ppm, at 15 percent oxygen on a dry basis (2019). The operator informed staff that typical emission levels for the turbine range between 4 ppm – 6 ppm, at 15 percent oxygen on a dry basis.

[1] Jeffrey Pierce & Ed Wheless. "Siloxanes in Landfill and Digester Gas Update", *27th Annual SWANA LFG Symposium*, March 2004.

Initial BARCT NOx Emission Limits and Other Considerations

Staff proposed initial NOx emission limits of 18.8 ppm, 12.5 ppm, and 5 ppm, at 15 percent oxygen on a dry basis. The proposed NOx emission limit of 18.8 ppm at 15 percent oxygen on a dry basis is based on the facility's claim that they can meet 18.8 ppm at 15 percent oxygen on a dry basis with increased water injection. The proposed NOx emission limit of 12.5 ppm is based on the lowest permitted limit for biogas fired turbines without SCR. The proposed NOx emission limit of 5 ppm at 15 percent oxygen on a dry basis emission limit is based on the achievable emission level with SCR.

Earlier in the rule development, staff proposed an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis for turbines not equipped with SCR. The proposed NOx emission limit was based on SCR's ability to reduce NOx by 90 percent. Ninety percent removal efficiency was determined by actual operations at two POTWs and supported by three suppliers. Staff determined that new turbines with uncontrolled emission levels of 25 ppm at 15 percent oxygen on a dry basis equipped with SCR with 90 percent NOx removal efficiency can meet 2.5 ppm at 15 percent oxygen on a dry basis. Stakeholders commented that an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis would result in the shutdown of existing beneficial use projects and deter facilities from implementing new beneficial use projects. Stakeholders also stated that gas treatment technology is not reliable due to the uncertainties involved with biogas contaminants and that meeting an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis consistently has the potential to be extremely difficult to achieve or unattainable.

Staff acknowledges that biogas content is unique to each facility and that gas treatment systems may need to be specifically designed to treat a facility's digester gas. However, many POTW facilities across the United States currently rely on gas treatment systems for combustion and post-combustion control operation. Within South Coast AQMD, five facilities use digester gas treatment with 12 engines with SCR and one POTW uses gas treatment with three turbines with SCR. Staff's assessment of current technology and applications suggest that gas treatment, along with SCR can reduce NOx emissions from combustion equipment. However, imposing an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis on a turbine with uncontrolled emissions of 25 ppm at 15 percent oxygen on a dry basis requires the SCR to perform with 90 percent efficiency. Although staff's technology assessment for SCR determined that SCR can remove NOx with 90 percent efficiency, staff increased the emission limit of 2.5 ppm to 5 ppm, at 15 percent oxygen on a dry basis, to allow a compliance margin for digester gas turbines. A new turbine with uncontrolled emission levels of 15 ppm at 15 percent oxygen on a dry basis would require the SCR to function at 67 percent efficiency and a new turbine with uncontrolled emissions of 25 ppm at 15 percent oxygen on a dry basis would require the SCR to function at 80 percent efficiency.

Staff also proposed an initial NOx emission limit for turbines without SCR to allow facilities an alternative to using SCR on digester gas fired turbines. Staff proposed an initial NOx emission limit of 12.5 ppm at 15 percent oxygen on a dry basis based on permitted limits and emissions analyses for biogas turbines without SCR.

Stakeholders expressed their concern about using a landfill turbine's performance as a comparison for a turbine's performance at a POTW. Staff followed up with the manufacturer of the turbine that achieves emission levels below 12.5 ppm, shown with source tests and CEMS data, to discuss the turbine's ability to meet a NOx emission limit of 12.5 ppm at 15 percent oxygen on a dry basis. The supplier stated that a 12.5 ppm NOx emission level could not be guaranteed. The guaranteed emission level for this turbine is 25 ppm at 15 percent oxygen on a dry basis. The supplier also informed staff that the POTW operating their turbine had emission levels higher than 12.5 ppm at 15 percent oxygen on a dry basis in its first year of operation. Given the additional information on this turbine model, staff is not proposing a separate emission level for turbines without SCR.

TABLE IX
INITIAL NOX EMISSION LIMITS FOR TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit effective on future compliance date*
Turbines ≥ 0.3 MW	18.8 ppm	5 ppm

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Cost-Effectiveness Analysis
Staff conducted cost-effectiveness analyses based on the initial NOx limits. The cost-effectiveness to meet 18.8 ppm at 15 percent oxygen on a dry basis is $48,600 per ton of NOx reduced, to be achieved by increased water injection. The average cost-effectiveness to meet 5 ppm at 15% oxygen on a dry basis is >$50,000 per ton of NOx reduced.

BARCT Emission Limits
Staff is proposing an emission limit of 18.8 ppm at 15 percent oxygen on a dry basis. The following table provides the proposed BARCT emission limits for turbines that fire digester gas or a digester gas blend with up to 40 percent natural gas.

TABLE X
PROPOSED BARCT EMISSION LIMITS FOR TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit Upon Turbine Replacement
Turbines ≥ 0.3 MW	18.8 ppm	BACT Emission Level

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

SUMMARY OF BARCT EMISSION LIMITS

Table XI contains a summary of proposed BARCT emission limits effective upon rule adoption and proposed BARCT emission limits effective upon equipment replacement. The facility with turbines permitted at 25 ppm at 15 percent oxygen on a dry basis are required to meet 18.8 ppm at 15 percent oxygen on a dry basis on or before rule adoption.

TABLE XI
EMISSION LIMITS AND COMPLIANCE SCHEDULE

Equipment Type	Limit at Rule Adoption*	Limit Upon Unit Replacement
Boilers ≤ 2 MMBtu/hr	30 ppm*	30 ppm*
Boilers ≤ 2 MMBtu/hr without permitted NOx concentration limits	Permit Limit	30 ppm*
Boilers > 2 MMBtu/hr	15 ppm*	BACT Limit
Turbines < 0.3 MW installed after May 3, 2013	9 ppm^	9 ppm^
Turbines ≥ 0.3 MW	18.8 ppm^	BACT Limit

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*
^All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.

CHAPTER 3: PROPOSED RULE 1179.1

INTRODUCTION

The following information describes the structure of PR 1179.1 and explains the provisions incorporated from other source-specific rules. New provisions and any modifications to existing provisions that were incorporated are also explained.

PROPOSED RULE STRUCTURE

PR 1179.1 will contain the following subdivisions that will contain all the requirements for the applicable equipment:

a) Purpose
b) Applicability
c) Definitions
d) Emission Limits
e) Source Testing
f) CEMS
g) I&M Plans
h) Diagnostic Emission Checks for Boilers and Engines
i) Recordkeeping
j) Other Requirements for Boilers
k) Other Requirements for Engines
l) Exemptions
Attachment 1) I&M Plan Elements

PROPOSED RULE 1179.1

Subdivision (a) – Purpose

The purpose of the rule is to limit emissions from combustion equipment located at a POTW. The regulated pollutants subject to PR 1179.1 include NOx, CO, and VOC for engines; and NOx and CO for boilers and turbines.

Subdivision (b) – Applicability

This rule applies to boilers, turbines < 0.3 MW, and engines, that fire digester gas or a blend of digester gas and natural gas, located at a POTW. Boilers and engines that fire only on natural gas are subject to the Rule 1146 series and Rule 1110.2, respectively. PR 1179.1 also applies to all turbines ≥ 0.3 MW located at a POTW, whether fired on digester gas, natural gas, or digester gas that is blended with natural gas, since Rule 1134 requirements (which regulates turbines) specifically exclude turbines located at POTW facilities.

Subdivision (c) – Definitions

Definitions in PR 1179.1 that applied in other source-specific rules are incorporated to define equipment, fuels, and other rule terms. New or modified definitions added to PR 1179.1 are:

- *DIGESTER GAS is gas that is derived from anaerobic decomposition of organic sewage or waste.*

This definition was added to describe a type of fuel used in equipment that PR 1179.1 applies to. The definition includes fuel derived from anerobic digestion of all organic waste, including sewage and food, that is used for fuel for combustion equipment located at a POTW.

- *ENGINE is any internal combustion equipment that is spark- or compression ignited and burns liquid and/or gaseous fuel to create heat that move pistons to do work.*

  This definition was added to describe a type of equipment PR 1179.1 applies to.

- *SHUTDOWN is the time that begins when an operator with the intent to shut down a unit reduces load and which ends in a period of zero fuel flow, unless otherwise defined in the South Coast AQMD permit to operate.*

  This definition was modified to differentiate a facility operation from a facility shutdown operation.

- *TURBINE is any internal combustion equipment that burns liquid and/or gaseous fuel to create hot gas that expands to move a rotor assembly, with vanes or blades, to do work.*

  This definition was added to describe a type of equipment PR 1179.1 applies to.

- *UNIT is a boiler, turbine, or engine subject to this rule.*

  This definition is added for clarity when referencing equipment subject to the requirements of PR 1179.1.

Subdivision (d) – Emission Limits

This subdivision establishes the NOx and other criteria pollutant emission limits for boilers, turbines, and engines.

Paragraph (d)(1) includes a Table 1, which contains the emission requirements for NOx, CO, and VOC for all the equipment subject to PR 1179.1. These emission requirements would not apply during periods of startup and shutdown, as further explained in paragraph (d)(4) – Startup and Shutdown.

Table 1 Concentration Limits for Boilers (at 3% O_2)

TABLE 1 **CONCENTRATION LIMITS**
BOILERS, STEAM GENERATORS, AND PROCESS HEATERS **FIRED ON DIGESTER GAS OR DIGESTER GAS BLEND**

EQUIPMENT CATEGORY	NOx (ppm)[1]	CO (ppm)[1]	VOC (ppm)	COMPLIANCE DATE
Rated heat input capacity > 2 MMBtu/hr	15	400	N/A	On or before [*Date of Adoption*]
Rated heat input capacity ≤ 2 MMBtu/hr	30			On or before [*Date of Adoption*]

[1] All parts per million (ppm) emission limits are referenced at 3% volume stack gas oxygen on a dry basis.

The NOx and CO concentration limits are listed for units fired on digester gas or a digester gas blend, along with the implementation schedule.

Boilers > 2 MMBtu/hr:

- Units that currently meet the Rule 1146/1146.1 limits of 15 ppm NOx at 3 percent oxygen on a dry basis can continue to comply with this limit
- All units will continue to meet the same current CO limit of 400 ppm from Rules 1146/1146.1

Boilers ≤ 2 MMBtu/hr:

- Units that currently have a permitted NOx limit of 30 ppm at 3 percent oxygen on a dry basis would continue to meet 30 ppm at 3 percent oxygen on a dry basis
- Units without a permitted NOx concentration limit would be exempt from emission limits in Table 1 and would meet 30 ppm at 3 percent oxygen on a dry basis upon burner or boiler replacement
- Units will continue to meet a CO concentration limit of 400 ppm at 3 percent oxygen on a dry basis, which is the same current limit for natural gas units covered under Rule 1146.2

Table 1 Concentration Limits for Turbines (at 15% O_2)

The NOx and CO concentration limits are listed for units fired on digester gas, a digester gas blend, or natural gas, along with the implementation schedule.

TURBINES FIRED ON DIGESTER GAS, DIGESTER GAS BLEND, OR NATURAL GAS				
EQUIPMENT CATEGORY	NOx (ppm)[2]	CO (ppm)[2]	VOC (ppm)	COMPLIANCE DATE
Rating ≥ 0.3 MW firing 40% natural gas or less	18.8	130	N/A	On or before [*Date of Adoption*]
Simple cycle with rating	5			On or before [*Date of Adoption*]

≥ 0.3 MW firing more than 40% natural gas				
Combined cycle with rating ≥ 0.3 MW firing more than 40% natural gas	2			On or before [*Date of Adoption*]
Rating < than 0.3 MW firing digester gas or digester gas with natural gas	9			On or before [*Date of Adoption*]

[1] All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis.

Turbines greater than or equal to 0.3 MW

- Units are required to meet 18.8 ppm NOx at 15 percent oxygen on a dry basis on or before the date of adoption of PR 1179.1

The above requirements are for turbines that fire 100 percent digester gas or a digester gas blend using 40 percent natural gas or less. Forty percent was chosen because it reflects the current permit thresholds for the use of natural gas supplementation for both of the affected facilities. It is the expectation that any unit that exceeds this threshold would be required to meet the same emission limits for 100 percent natural gas-fired turbines. There are no units firing on more than 40 percent natural gas at a POTW currently.

- Simple cycle turbines blending more than 40% natural gas would meet 5 ppm at 15 percent oxygen on a dry basis on or before the date of rule adoption
- Combined cycle turbines blending more than 40% natural gas would meet 2 ppm at 15 percent oxygen on a dry basis on or before the date of rule adoption

The CO emission limit for all turbines is based on that contained in the affected facility permits. If a permit contains a more stringent CO limit than what the rule contains, it must comply with the more stringent limit

Turbines less than 0.3 MW

These turbines, more commonly referred to as microturbines, will be subject to the requirements of PR 1179.1 when firing digester gas or a digester gas blend. Units that were installed before January 1, 2013 that are permit exempt and not subject to a NOx limit would meet 9 ppm upon turbine replacement. Units would also be subject to the 130 ppm CO concentration limit.

Table 1 Concentration Limits for Engines (at 15% O_2)

Engines that are fired on digester gas or a digester gas blend are subject to a NOx limit of 11 ppm at 15 percent oxygen on a dry basis, a CO limit of 250 ppm at 15 percent oxygen on a dry basis, and a VOC limit of 30 ppm at 15 percent oxygen on a dry basis. These are the same requirements as those contained in Rule 1110.2. Natural gas engines located at POTWs would continue to comply with all requirements contained in Rule 1110.2.

ENGINES FIRED ON DIGESTER GAS OR DIGESTER GAS BLEND				
EQUIPMENT CATEGORY	NOx (ppm)[2]	CO (ppm)[2]	VOC (ppm)[3]	COMPLIANCE DATE
Engines > 50 bhp	11	250	30	On or before [*Date of Adoption*]

[1] All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis.

[2] Parts per million (ppm) by volume, measured as carbon, corrected to 15% oxygen on a dry basis.

Emission limits for boilers that fire digester gas simultaneously with natural gas – Paragraph (d)(2)

Boilers that fire digester gas and natural gas simultaneously are subject to the digester gas NOx emission limit when firing 10 percent or less natural gas. If the natural gas percentage threshold is exceeded, then the unit must comply with a weighted average limit, taking into account the compliance limits of both fuels as well as their individual heat inputs. Equation 1 in PR 1179.1 is the same equation that is currently contained in Equations 1146-1 and 1146.1-1 of the December 7, 2018 amended versions of Rules 1146 and 1146.1. Owners and operators of these units must comply with either the weighted average limit or with the natural gas NOx limit, and must install a non-resettable, totalizing fuel flow meter to measure the flows for each fuel used in Equation 1.

$$\text{Weighted Average Limit} = \frac{(CL_A \; x \; Q_A) \; + \; (CL_B \; x \; Q_B)}{Q_{A} + \; Q_B} \quad \text{(Equation 1)}$$

Where:

CL_A = compliance limit for digester gas

Q_A = heat input from digester gas

CL_B = compliance limit for natural gas pursuant to Rule 1146 and Rule 1146.1

Q_B = heat input from natural gas

Averaging Times for Units with CEMS – Paragraph (d)(3)

PR 1179.1 provides averaging time requirements for boilers, turbines, engines with CEMS. The proposed averaging times are as follows:

- Boilers: Fixed interval of 1 hour for NOx and CO
- Turbines: Rolling period of 1 hour
- Engines (same as current Rule 1110.2 requirements):
    - Fixed interval of 1 hour
    - Fixed interval of 24 hours when at or below 11 ppm at 15 percent oxygen on a dry basis NOx and 250 ppm at 15 percent oxygen on a dry basis CO (contained in permit to operate before November 1, 2019)

- Fixed interval of 48 hours when at or below 9.9 ppm at 15 percent oxygen on a dry basis NOx and 225 ppm CO at 15 percent oxygen on a dry basis (contained in permit to operate)

Startup and Shutdown – Paragraph (d)(4)

Startup and shutdown requirements are provided in PR 1179.1 for boilers, turbines, and engines and are as follows:

- Boilers without SCR: Not longer than 6 hours (same as current Rule 1146 requirements)
- Boilers with SCR: Not longer than is necessary to reach minimum catalyst operating temperature for startup and not longer than 6 hours for startup or shutdown
- Turbines without SCR: Not longer than 30 minutes
- Turbines with SCR: Not longer than 1 hour
- Engines (same as current Rule 1110.2 requirements):
  - Not longer than 30 minutes unless a longer time period, less than 2 hours, is specified in the permit
  - Not longer than 4 operating hours for major repairs or installation of catalytic control equipment (as explained in the staff report for the November 2019 amendments to Rule 1110.2)
  - Not longer than 150 operating hours for initial commissioning of a new engine
  - Not longer than the period specified on the permit for the initial commissioning period of a new engine

Prohibition of liquid fuel – Paragraph (d)(5)

PR 1179.1 contains a prohibition on the use of any liquid fuel, such a diesel, for the operation of any turbine at a POTW. This provision would not apply to emergency use turbines as described in the proposed exemptions under subdivision (l).

Subdivision (e) – Source Testing

For units and for pollutants not subject to CEMS, PR 1179.1 provides a source testing schedule in Table 2.

TABLE 2 SOURCE TESTING SCHEDULE			
Equipment Category	**Frequency**	**Pollutant**	**Required Operating Time Prior to Conducting Source Test[1]**

Boilers ≥ 10 MMBtu/hr	Every 3 years from the date the previous source test was required	NOx, CO	At least 250 operating hours or at least 30 days
Boilers < 10 MMBtu/hr and > 2 MMBtu/hr	Every 5 years from the date the previous source test was required		
Turbines emitting ≥ 25 tons NOx per year	Once every calendar year		None
Turbines emitting < 25 tons of NOx per year	Every 3 years from the date the previous source test was required		
Engines	Every 2 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due, or every 8,760 operating hours, whichever occurs first.[2]	NOx, CO, and VOC reported as carbon	At least 40 operating hours or at least 1 week

1 Time that a unit must be in operation subsequent to any tuning or servicing, unless tuning or servicing is due to an unscheduled repair.

2 Frequency may be reduced once every 3 years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated before the date a source test is due, the source test shall be conducted by the end of 7 consecutive days or 15 cumulative days of resumed operation. An owner or operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

The boiler requirements are the same as those contained in Rules 1146/1146.1, while the turbine requirements reflect those contained in Rule 1134. The source testing requirements would apply to all turbines, including those less than 0.3 MW. Lastly, the engine requirements reflect the same requirements currently contained in Rule 1110.2.

Other source testing requirements, which come from existing source testing requirements from other source-specific rules, such as Rule 1110.2, are contained in PR 1179.1 and apply to all the applicable equipment types.

Source Test Protocol Submittal and Scheduling - Paragraph (e)(2)

PR 1179.1 provides 60 days before a scheduled source test date for the owner or operator to submit a source test protocol for approval. A new requirement is included in (e)(2)(B) that requires a new submittal of a source testing protocol if any modification to the equipment results in a change to the permit, if any emission limits have changed, or at the request of the Executive Officer. A new submittal may be required, for example, if the prior source testing protocol is outdated. If there is a delay in the approval of the source test protocol, the owner or operator is allowed 90 days from the date of approval to conduct the source test.

Source Test Protocol Requirements - Paragraph (e)(3)

Contains requirements for the information required for submitting a protocol, in addition to further requirements pertaining to VOC for engines under subparagraph (e)(3)(A).

Source Test Date Notification - Paragraph (e)(4)

Contains requirements for notification of a scheduled source test.

Approved Contractor and Test Methods - Paragraph (e)(5):

Contains requirements for source testing that is to be conducted by a South Coast AQMD-approved contractor. Contains a listing of source testing methods in Table 3.

TABLE 3
SOURCE TESTING METHODS

Pollutant	**Test Methods**
NOx	South Coast AQMD Test Methods 100.1 or 7.1
CO	South Coast AQMD Test Methods 100.1 or 10.1, or EPA Test Method 10
CO_2 and O_2	South Coast AQMD Test Method 3.1 or 100.1
VOC	South Coast AQMD Test Methods 25.1 or 25.3, excluding ethane and methane
Particulate Matter (PM)	South Coast AQMD Test Method 5.1, 5.2, or 5.3

Operating Conditions During Source Testing - Paragraph (e)(6)

Contains requirements on conducting source tests in the as-found operating condition, and that no testing should be completed during periods of startup, shutdown, or under breakdown conditions. In addition, subparagraph (e)(6)(A) contains specific operating load (actual duty cycle) requirements for the source testing of engines, which are the same requirements as those currently under Rule 1110.2.

Submittal of Completed Source Test - Paragraph (e)(7)

Facilities are required to submit the completed source test within 60 days of completion.

Periodic Monitoring - Paragraph (e)(8)

Provides an option for owners or operators of boilers at Title V facilities to conduct periodic monitoring or testing as required by the Title V permit in lieu of conducting a source test per the requirements above.

Subdivision (f) – CEMS

This subdivision contains the requirements for the installation, operation, and maintenance of CEMS equipment. Many of these requirements are also contained in Rule 218 and 218.1, which currently address monitoring requirements and performance specifications. It should be noted that proposed rules 218.2 and 218.3 are currently under development and will contain enhanced monitoring and performance specification requirements. Equipment subject to this rule would also be required to comply with Rules 218/218.1 as well as Rule 218.2/218.3, upon adoption. Table 4 in subdivision (f) contains the thresholds for boilers, turbines, and engines for requiring CEMS, consistent with current requirements in Rules 1146, 1134, and 1110.2, respectively.

TABLE 4
UNITS REQUIRING CEMS

Equipment Type	Threshold	Pollutant(s)
Boilers	Rated heat input capacity > 40 MMBtu/hr and an annual heat input > 200 x 10^9 Btu per year	NOx
Turbines	Output capacity rating ≥ 2.9 MW	NOx
Engines	Output capacity rating ≥ 1000 bhp and operating more than 2 million bhp-hr per calendar year	NOx, CO
	Combined output capacity rating ≥1500 bhp and a combined fuel usage of >16 x 10^9 Btu per year (higher heating value) of engines at the same location[1]	

[1] Engines as of October 1, 2007, located within 75 feet of another engine (measured from engine block to engine block) are considered at the same location.

Turbine Parameter Monitoring - Paragraph (f)(1)

Provides parameter monitoring requirements, specific to turbines using CEMS.

CEMS Requirements for Engines - Paragraph (f)(2)

Subparagraphs (f)(2)(A) and (f)(2)(B) contain CEMS requirements for engines, as well as an aggregate threshold requirement for co-located engines, as well as exceptions.

Subparagraph (f)(2)(C) contains new requirements introduced into Rule 1110.2 during the November 2019 amendments which allow engines 1,000 bhp and greater and less than 1,200 bhp to conduct weekly diagnostic checks in lieu of installing a CEMS. However, if there are three or more emissions exceedances in any 12-month period, the owner or operator will be required to install CEMS.

Subparagraph (f)(2)(D) provides requirements for installing CEMS upon exceedance of the threshold.

Subparagraph (f)(2)(E) allows for an existing NOx CEMS to be taken out of service for up to a 2 week time period to add CO CEMS.

Subparagraph (f)(2)(F) provides additional requirements for monitoring and for allowing relative accuracy testing audits (RATAs) to be performed on the same testing schedule for source tests, despite the annual RATA requirements of Rule 218.1.

Subparagraph (f)(2)(G) provides additional clarity for engines installed at the same location. New engines cannot be installed farther than 75 feet away from each other to avoid circumvention of the aggregate engine CEMS threshold.

Subparagraph (f)(2)(H) provides requirements for new engines that are issued a permit to construct to comply with CEMS or I&M plan requirements upon commencement of operation.

Subdivision (g) – I&M Plans

This subdivision contains the I&M plan requirements that are consistent with those currently in Rule 1110.2. Owners and operators are required to have an I&M plan approved for their facility that contains the items that are listed in Attachment 1 of PR 1179.1. Attachment 1 contains the same elements as Attachment 1 of Rule 1110.2. Since PR 1179.1 will apply to digester gas fired engines, owners and operators of engines that are covered by both Rule 1110.2 for natural gas and 1179.1 for digester gas would require one I&M plan for each rule. Owners and operators of PR 1179.1 equipment would be required to submit an I&M plan application within three months of rule adoption [subparagraph (g)(1)(C)].

Subdivision (h) – Diagnostic Emission Checks for Boilers and Engines

This subdivision contains requirements that are consistent with current requirements in Rules 1146/1146.1 and in Rule 1110.2. Diagnostic emission checks are required to be conducted by trained staff in accordance with the Combustion Gas Periodic Monitoring Protocol for boilers and engines subject to Rule 1146, 1146.1, and 1110.2. The minimum sampling time for diagnostic emission checks is 15 minutes.

<u>Diagnostic Checks for Boilers - Paragraph (h)(1)</u>

Provides diagnostic emission check requirements for boilers. Testing frequency is separated by boiler size and allows for the owner or operator to resolve any problems in the event of an emissions exceedance. Any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance will be a violation.

Diagnostic Checks for Engines - Paragraph (h)(2)
Provides diagnostic emission check requirements for engines, including testing frequency and additional requirements for lean-burn engine operators. As with boilers, any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance will be a violation.

Subdivision (i) – Recordkeeping

This subdivision harmonizes the recordkeeping requirements for the various types of equipment that will be subject to PR 1179.1. PR 1179.1 would additionally require owner or operators to maintain maintenance, service and tuning records. Subdivision (i) would require records to be retained by facility owners and operators for 5 years. Other source-specific rules contained shorter records retention timeframes (such as 2 years). Accumulation of the records would begin upon date of adoption.

Recordkeeping for Boilers - Paragraph (i)(1)

Subparagraph (i)(1)(A) requires owners or operators to maintain a daily operating log for all boilers. Subparagraph (i)(1)(B) provides recordkeeping requirements specific to operators of boilers that fire digester gas and natural gas simultaneously, which are used to calculate the weighted average NOx concentration limit. Parameters include fuel flow readings for each of the fuels used, the percentage of each gas utilized, as well as the higher heating value of the fuels on a monthly basis.

Recordkeeping for Turbines - Paragraph (i)(2)

Provides recordkeeping requirements for operators of turbines, as well as the parameters used, such as hours of operation, type of fuel used, and startup and shutdown times. In addition, this paragraph also requires recordkeeping of emission control system operation and maintenance to verify continuous operation while the turbine is in operation.

Recordkeeping for Engines - Paragraph (i)(3)

Provides the monthly operating log requirements for owners and operators of engines subject to PR 1179.1.

Subdivision (j) – Other Requirements for Boilers

This subdivision contains additional requirements specific to boilers and consistent with current requirements from Rules 1146, 1146.1, and 1146.2.

Derating Boilers - Paragraph (j)(1)

Provides a requirement that an owner or operator cannot derate any boiler to less than or equal 2 MMBtu/hr to circumvent permitting and emissions requirements.

Maintenance for Small Boilers - Paragraph (j)(2)

Provides maintenance and documentation requirements for small boilers rated less than or equal to 2 MMBtu/hr.

Subdivision (k) – Other Requirements for Engines

This subdivision contains other requirements that are specific for engines and that are consistent with current requirements of Rule 1110.2 that pertain to reporting, breakdowns, and other equipment requirements.

Engine Breakdowns - Paragraph (k)(1)

Provides the requirements for breakdown conditions or emissions exceedances from diagnostic emission checks. Subparagraph (k)(1)(B) contains excess emission thresholds for breakdowns in Table 5. These are the same requirements that were adopted during the December 2015 amendments to Rule 1110.2 to limit the number of breakdowns that can occur during any calendar quarter as a way to provide a quantification of excess emissions due to these types of events. For biogas engines, these limits are effective until compliance with the limits of Table 1. Almost all biogas engines now comply with the emission limits in Table 1, however, there are two operators that are currently operating under variances until that equipment is replaced with either compliant equipment or near-zero emitting equipment, such as fuel cells.

TABLE 5

EXCESS EMISSION CONCENTRATION THRESHOLDS FOR BREAKDOWNS

Equipment Category	NO_x (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000
Biogas Engines[2]	185	2000

1 Corrected to 15% oxygen

2 Effective up to the time of compliance with the limits specified in Table 1, after which the thresholds revert to the applicable lean- or rich-burn engine limits.

Totalizing Meters for Engines - Paragraph (k)(2)

Provides requirements for maintaining a non-resettable totalizing time meter for engines.

Air-to-Fuel Ratio Controller for Engines - Paragraph (k)(3)

Provides requirements for maintenance of combustion controls for engines without CEMS.

Breakdown Reporting for Engines - Paragraph (k)(4)

Provides reporting requirements for breakdowns that result in emissions exceedances along with the required documentation for these events. The quarterly reports that are also required for natural gas engines under Rule 1110.2 would also be required for digester gas engines under PR 1179.1. These reports would contain each occurrence of a breakdown, fault, malfunction, alarm, engine or control system parameter out of range, or a diagnostic emission check that results in an emissions exceedance.

Subdivision (l) – Exemptions

Low-Use Boilers - Paragraph (l)(1)

Provides low fuel use exemptions for any boilers previously subject to Rule 1146 that were in operation before September 5, 2008 with an annual heat input usage less than or equal to 9.0×10^9 Btu per year (90,000 therms). Owners and operators with such units at POTWs would follow the tune up procedures that are contained in Rule 1146 (c)(5). The low use provisions for boilers that would be subject to Rule 1146.1 are not included in PR 1179.1 because there were no such units identified in the POTW universe. Any low use boiler referenced in this paragraph would be exempt from Table 1 requirements because it is the expectation that any unit would need to comply with those emission requirements at the time of burner or unit replacement.

Special Use Turbines - Paragraph (l)(2)

Provides exemption to turbines that are used only for firefighting or flood control. In addition, an exemption from PR 1179.1 requirements is provided for emergency standby turbines, which are defined here and in Rule 1134. An owner or operator must maintain an hour meter and a log to verify that each emergency standby turbine does not exceed a usage limit of 200 hours per year. If the usage threshold is exceeded, the owner or operator would be required to submit a permit application to meet the applicable compliance limits of PR 1179.1.

Natural Gas Firing Boilers and Engines - Paragraph (l)(3)

Provides an exemption for units firing exclusively natural gas. Natural gas boilers at POTWs would remain subject to the requirements of the Rule 1146 Series, depending on size (Rules 1146, 1146.1, 1146.2). Dual fuel boilers that are firing 100% natural gas would also be subject to the Rule 1146 Series requirements. Natural gas engines would remain subject to the requirements of Rule 1110.2.

Low-Use Engines - Paragraph (l)(4)

Provides an exemption for engines that operate 200 hours or less per year. The engine usage would need to be verified with the installation of a non-resettable engine hour meter and with the maintenance of an operating log. Staff identified low-use digester gas engines that would be exempt from PR 1179.1.

Permit Exempt Turbines < 0.3 MW - Paragraph (l)(5)

Provides an exemption from rule requirements for turbines that were in operation before May 3, 2013 and are currently permit exempt.

Boilers Without Permitted NOx Concentration Limits - Paragraph (l)(6)
Provides an exemption for boilers without permitted NOx concentration limits. The boilers would be exempt from the emission limits in Table 1. The emission limits in Table 1 become effective upon a burner or boiler replacement.

Attachment 1 – I&M Plan Elements

Attachment 1 applies for engines with I&M plans subject to PR 1179.1 subdivision (g). These parameters and procedures are consistent with those contained in Rule 1110.2.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

POTW equipment is currently subject to source specific, with the exception of turbines greater than or equal to 0.3 MW. PR1179.1 will contain all applicable provisions from source specific rules that facilities currently comply with. Some provisions were not contained in source specific rules but were a condition on facility equipment permits. The provisions that will impact emissions from POTWs apply to three turbines located at one facility.

EMISSION REDUCTIONS

PR 1179.1 will result in emission reductions for turbines ≥ 0.3 MW. Boilers and engines will remain at the current rule limits and/or permit limits, with the exception of four boilers that are not permitted with a NOx concentration limit. Reductions for the boilers without permitted NOx concentration limits were not determined because baseline emissions are not known. The reductions for the boilers without permitted NOx concentration limits are estimated to be negligible. Baseline emissions for turbines were determined using 2019 Annual Emissions Reports (AER).

Emission Reduction Estimate for Turbines

The total baseline emissions for the facility impacted by the proposed emission limit are 131,513 pounds per year or 0.18 tons per day. The turbines are permitted at 25 ppm at 15 percent oxygen on a dry basis. The baseline emissions for the other facility operating three turbines are 96,854 pounds or 0.133 tons per day. These turbines are permitted at 18.8 ppm at 15 percent oxygen on a dry basis. The proposed emission limit of 18.8 ppm would only affect the facility permitted at 25 ppm. The proposed emission limit would become effective upon rule adoption and the reductions realized are 0.05 tons per day.

COST-EFFECTIVENESS

The California Health & Safety Code (H&SC) Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control technology is measured in terms of the control cost in dollars per ton of air pollutant reduced. The costs for the control technology includes purchasing, installation, operating, and maintaining the control technology. Emissions reductions were based on the 2019 AER and the most recent source test data for turbines. The 2016 AQMP established a cost-effectiveness threshold of $50,000 per ton of NOx reduced. The cost-effectiveness is estimated based on the present worth value of the control cost, which is calculated according to the capital cost (initial one-time equipment, installation, and startup costs) plus the annual operating cost (recurring expenses over the useful life of the control equipment times a present worth factor). In the cost-effectiveness calculation, staff assumed a uniformed series present worth factor (PWF) at a 4% interest rate and a 25-year equipment life expectancy.

$$PWV = TIC + (PWF \times AC)$$

PWV = present worth value ($)

TIC = total installed cost ($)
AC = annual cost ($)
PWF = uniform series present worth factor (15.622)

Boilers ≤ 2 MMBtu/hr

A cost-effectiveness analysis was conducted for boilers 1-2 MMBtu/hr to meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis and boilers < 1 MMBtu/hr to meet a NOx concentration limit of 20 ppm at 3 percent oxygen on a dry basis. Staff used costs from the Rule 1146 series cost analysis of low NOx burners for units ≤ 2 MMBtu/hr. The cost for low NOx burner replacements for boilers ≤ 2 MMBtu/hr is $20,000. This cost was used to calculate cost-effectiveness. The cost-effectiveness to replace existing burners on boilers 1-2 MMBtu/hr with a burner that can meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced. The cost-effectiveness to replace existing burners on boilers < 1 MMBtu/hr with a burner that can meet a NOx concentration limit of 20 ppm at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced.

Boilers > 2 MMBtu/hr

A cost-effectiveness analysis was conducted for boilers to meet 12 ppm at 3 percent oxygen on a dry basis. Staff used costs from the Rule 1146 series cost analysis of low NOx burners for units > 2 MMBtu/hr. Equipment costs ranged from $40,000-$350,000 depending on the size and the installation costs ranged from $25,000-$125,000 depending on size. The average cost for a low NOx burner that can meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis with installation is $90,300. The average cost-effectiveness to retrofit boilers with a burner that can meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced.

Turbines ≥ 0.3 MW

Staff obtained costs for control equipment from a variety of sources that included facilities, suppliers, and cost-estimation tools. The cost for control equipment considers capital costs and annual costs. Capital costs are one-time costs that cover the components required to assemble a project. These costs include, but are not limited to, equipment, installation, permitting, consulting, and testing. Annual costs are any recurring costs required to operate equipment. These costs include operating and maintenance (O&M) costs such as electricity, monitoring, and costs for consumables.

Selective Catalytic Reduction

SCR costs were obtained from facilities, U.S EPA's Air Pollution Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR), two engineering consultants, one catalyst supplier, and applicable costs from the Rule 1110.2 cost analysis for SCR (2012 Technology Assessment). The costs for SCR considered retrofitting three turbines that currently do not utilize SCR. The design parameters used to obtain SCR cost estimates and costs from various sources are shown in Table XII and Table XIII.

Table XII
SCR DESIGN PARAMETERS

HHV	665 Btu/scf
Inlet NOx	22 ppm

Removal efficiency	90%
Exhaust flowrate	~325,000 lbs/hr
Operating days/year	365
Operating life of catalyst	24,000 hours
Ammonia slip	5 ppm
Inlet temperature	866 F
Electricity	$0.19/kwh - $0.25/kwh

Table XIII
SCR COST ESTIMATES

Source	Capital Cost	Annual Costs
EPA Cost Manual	$8.3 million	$1.2 million
Supplier A	$8.0 million	$489,5000
Supplier B	2.5 million*	$450,000
Rule 1110.2 staff report (11/19)	$1.4 million - $6.6 million	EPA Cost Manual
Facility A	Unavailable	$38,000 (3 SCRs) new - no catalyst replacement^
Facility B	Unavailable	$48,000 (5 SCRs) new - no catalyst replacement^
Average cost for 3 SCRs	$7.6 million	$458,5000

* Identified as outlier and not included in the average capital cost.

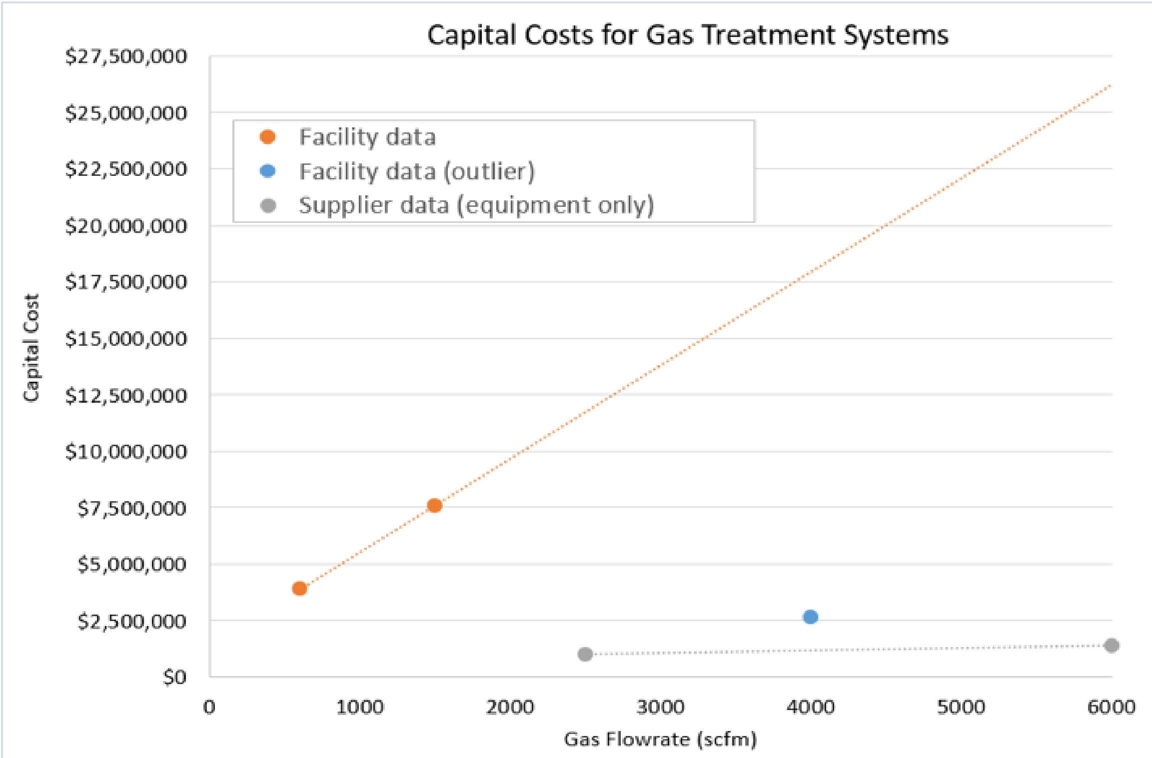
^ Annual costs provided by Facilities A and B did not include cost for catalyst due to new installations that have not required a catalyst replacement. An added annual cost of $33,000 (not shown in table) was added to Facility A's and Facility B's annual costs for catalyst. The added costs were included in the average cost annual costs.

Gas Treatment

Costs for gas treatment were obtained from POTWs and landfills within California. Costs reflect gas treatment systems designed to remove siloxanes to < 100 ppb from gas streams that have reported inlet siloxane levels of < 15 ppm.

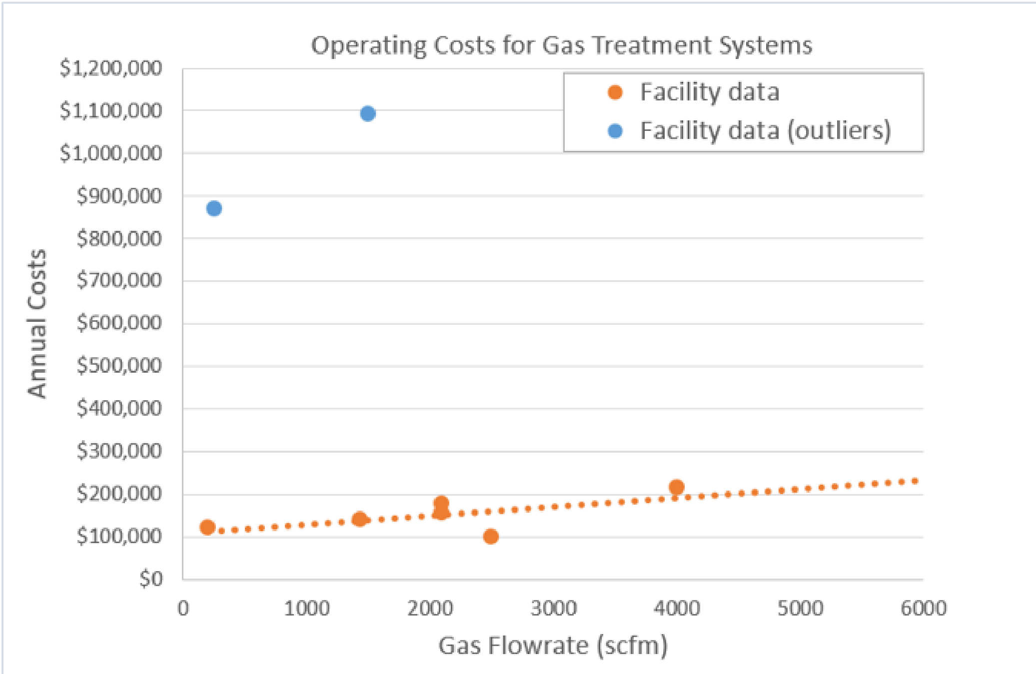
One outlier for cost information was identified and the data was not considered in determining capital costs. One supplier provided two cost estimates for two flowrates. The supplier provided only equipment costs. Figure 4-1 shows the data used to determine a capital cost for a gas treatment system in relation to gas flowrate.

Figure 4-1 – Capital Costs for Gas Treatment Systems



Annual costs for gas treatment systems were provided by eight facilities. The facilities had reported siloxane levels between 4.4 ppm – 15 ppm. One facility treated digester gas to PUC pipeline quality gas. This facility had the highest operating costs of approximately one million dollars with over half the costs attributed to electricity needs. Four other facilities have not considered electricity as a significant cost in the costs they provided for their gas treatment systems. The facility whose cost information reflected a gas treatment system that treats gas to PUC pipeline quality was identified as an outlier. One other facility's data was identified as an outlier. Figure 4-2 shows the data obtained from facilities for annual costs of gas treatment systems in relation to gas flowrate.

Figure 4-2 – Operating Costs for Gas Treatment Systems



The cost information used to determine cost-effectiveness to meet 5 ppm at 15 percent oxygen on a dry basis was identified for a gas treatment system that requires treatment of 6,000 scfm of digester gas. The capital cost determined was $26,250,000 and the annual O&M costs were $250,000.

New Turbines

Costs were analyzed for new turbines that can meet 5 ppm at 15 percent oxygen on a dry basis with existing SCRs. The facility that currently uses SCR would be required to replace their turbines with uncontrolled NOx of 213 ppm at 15 percent oxygen on a dry basis turbines for turbines with uncontrolled NOx of 15 ppm at 15 percent oxygen on a dry basis, to meet 5 ppm at 15 percent oxygen on a dry basis. Costs for new turbines that can meet 15 ppm at 15 percent oxygen on a dry basis were obtained from the EPA Catalog of CHP Technologies. The EPA Catalog of CHP Technologies estimates capital costs for new turbines at $1.2 - $1.5 million per megawatt, and annual costs at $0.0092-$0.0093 per kilowatt-hour. The three turbines currently equipped with SCR have a power output capacity of 41.85 MW. The capital cost at $1.5 million/MW is $62,800,000. The annual cost at $0.0093/kwh is $3,400,000. The cost-effectiveness for the turbines with SCR to meet 5 ppm at 15 percent is $253,200, including stranded assets.

Water Injection

Staff obtained costs from one facility and one demineralized water supplier to determine the cost-effectiveness of a NOx concentration limit of 18.8 ppm limit at 15 percent oxygen on a dry basis. The facility stated that up to 8,000 gallons per day, per turbine, of demineralized water is needed to meet a NOx concentration limit of 18.8 ppm at 15 percent oxygen on a dry basis and has stated that a general cost for demineralized water is ten times the cost of potable water. Utility water rates were obtained from LADWP’s website that stated a cost of $0.0071 per gallon as the industrial water rate. At ten times the utility water rate ($0.071 per gallon), the annual cost to meet a NOx concentration limit of 18.8 ppm at 15 percent oxygen on a dry basis is $204,400 per turbine. The demineralized water supplier quoted a cost of $0.0281 per gallon that included the cost that included exchange costs, delivery, and rental fees. The annual cost to meet a NOx concentration limit of 18.8 ppm at 15 percent oxygen on a dry basis is based on the supplier's quote is $82,052 per turbine. An average of the two annual cost estimates of $143,226 per turbine was used to calculate cost-effectiveness.

The cost-effectiveness was calculated for three emission limits: 18.8 ppm and 5 ppm, at 15 percent oxygen on a dry basis. Table XIV summarizes of the cost-effectiveness to require existing turbines to meet each limit.

Table XIV – Cost-Effectiveness for Proposed Turbine Emission Limits

Cost-Effectiveness to Meet 18.8 ppm at 15 percent oxygen on a dry basis	
Emission Reductions Over 25 Years	Cost-Effectiveness
138 tons (Facility 1)	$48,600 per ton of NOx reduced
0 tons (Facility 2)	Currently permitted at 18.8 ppm at 15 percent oxygen on a dry basis

Cost-Effectiveness to Meet 5 ppm at 15 percent oxygen on a dry basis	
Emission Reductions Over 25 Years	Cost-Effectiveness
1492 tons (Facility 1 – turbines without SCR)	$30,200 per ton of NOx reduced
830 tons (Facility 2 – turbines with SCR)	$206,200 per ton of NOx reduced

The cost-effectiveness to meet the proposed NOx BARCT emission limit of 18.8 ppm at 15 percent oxygen on a dry basis is $48,600 per ton of NOx reduced. The average cost-effectiveness to meet the proposed NOx BARCT emission limit of 5 ppm at 15 percent oxygen on a dry basis is $118,200 per ton of NOx reduced.

The proposed emission limits for boilers and turbines are not cost-effective with the exception of the NOx BARCT emission limit of 18.8 ppm at 15 percent oxygen on a dry basis that would apply to turbines. The proposed NOx BARCT emission limit of 18.8 ppm at 15 percent oxygen on a dry basis is proposed to be effective upon the date of adoption. A summary of the cost-effectiveness analysis is in Table XV.

Table XV – Cost-Effectiveness Analysis

Category	**TIC ($)**	**AC ($)**	**PWV ($)**	**NOx Reductions tpd**	**CE ($/ton)**

Boilers < 1 MMBtu/hr	N/A	N/A	N/A	0.00004	N/A
Boilers 1 – 2 MMBtu/hr	N/A	N/A	N/A	0.0005	N/A
Boilers > 2 MMBtu/hr	N/A	N/A	N/A	0.0021	N/A
Turbines ≥ 0.3 MW (To meet 18.8 ppm)	N/A	429,800	6.7 MM	0.0515	48,600
Turbines ≥ 0.3 MW (To meet 5 ppm from 18.8 ppm)	N/A	N/A	N/A	0.0629	N/A

SOCIOECONOMIC ASSESSMENT

A socioeconomic impact assessment will be conducted and released for public review and comment at least 30 days prior to the South Coast AQMD Governing Board Hearing which is anticipated to be heard on October 2, 2020.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's certified regulatory program (Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l) and South Coast AQMD Rule 110), the South Coast AQMD, as lead agency, is reviewing the proposed project to determine if it will result in any potential adverse environmental impacts. Appropriate CEQA documentation will be prepared based on the analysis.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Draft Findings
California Health and Safety Code Section (H&SC) 40727 requires that prior to adopting, amending or repealing a rule or regulation, the South Coast 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
PR 1179.1 is needed to establish NOx, CO, and/or VOC emission limits for digester gas and/or natural gas fired boilers, turbines, and engines located at publicly owned treatment works (POTWs) that are representative of BARCT, as well as monitoring, reporting, and recordkeeping requirements.

Authority
The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to H&SC Sections 39002, 39616, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508.

Clarity

PR 1179.1 is written or displayed so that their meaning can be easily understood by the persons directly affected by them.

Consistency
PR 1179.1 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication
PR 1179.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference
In amending these rules, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: H&SC Sections 39002, 40001, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Under H&SC Section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing rules from other air quality management districts and/or air pollution control districts, and existing or proposed SCAQMD rules and air pollution control requirements and guidelines which are applicable to natural gas and/or digester gas fired turbines and digester gas fired boilers or steam generators. See Table XVI and Table XVII below.

Table XVI: PR 1179.1 Comparative Analysis- Turbines

Rule Element	PR 1179.1	BAAQMD Regulation 9 Rule 9	SMAQMD Rule 413	SJVAPCD Rule 4703	40 CFR Part 60 Subpart GG	40 CFR Part 60 Subpart KKKK
Applicability	Located at a POTW facility: Turbines < 0.3 MW fueled by digester gas or a digester gas blend and turbines ≥ 0.3 MW fueled by natural gas, digester gas, or a digester gas blend.	Stationary gas turbines with a heat input rating ≥ 5 MMBtu/hr	Stationary gas turbines with ratings equal to or greater than 0.3 megawatt (MW) output, or 3 MMBTU/hr input and operated on gaseous and/or liquid fuel.	Stationary gas turbines with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour.	Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction on or before 2/18/2005	Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction after 2/18/2005

Requirements	NOx emission limits @ 15% O_2: • ≥ 0.3 MW firing 40% natural gas or less – 18.8 ppm on or before date of adoption • Simple cycle ≥ 0.3 MW firing more than 40% natural gas- 5 ppm on or before date of adoption • Combined cycle ≥ 0.3 MW firing more than 40% natural gas- 2 ppm on or before date of adoption • <0.3 MW firing digester gas or digester gas with natural gas- 9 ppm on or before date of adoption CO emission limit @15% O_2: 130 ppm	General NOx emission limits (@ 15% O_2) for refinery fuel gas, waste gas or LPG: • < 5 MMBtu/hr- Exempt • 5 – 50 MMBtu/hr – 2.53 lbs/MWhr or 50 ppmv • > 50 – 150 MMBtu/hr – 2.34 lbs/MWhr or 50 ppmv • > 150 – 250 MMBtu/hr – 0.70 lbs/MWhr or 15 ppmv • > 250 – 500 MMBtu/hr – 0.43 lbs/MWhr or 9 ppmv • > 500 MMBtu/hr – 0.26 lbs/MWhr or 9 ppmv General NOx emission limits (@ 15% O_2) for natural gas: • < 5 MMBtu/hr- Exempt • 5 – 50 MMBtu/hr - 2.12 lbs/MWhr or 42 ppmv • > 50 – 150 MMBtu/hr (no retrofit available) – 1.97 lbs/MWhr or 42 ppmv • > 50 – 150 MMBtu/hr (WI/SI enhancement available) – 1.64 lbs/MWhr or 35 ppmv • > 50 – 150 MMBtu/hr (DLN technology available) – 1.17 lbs/MWhr or 25 ppmv • > 150 – 250 MMBtu/hr – 0.70 lbs/MWhr or 15 ppmv • > 250 – 500 MMBtu/hr – 0.43	NOx emission limits (@ 15% O_2) for gaseous fuel: • ≥ 0.3 to < 2.9 MW – 42 ppmv • ≥ 2.9 MW (operating < 877 hr/yr) – 42 ppmv • ≥ 2.9 to < 10 MW (operating ≥ 877 hr/yr) – 25 ppmv • ≥ 10 MW (no SCR, operating ≥ 877 hr/yr) – 15 ppmv • ≥ 10 MW (with SCR, operating ≥ 877 hr/yr) – 9 ppmv	NOx emission limits (@ 15% O_2) for gas fuel: • < 3 MW – 9 ppmvd • 3 – 10 MW pipeline gas turbine – 8 ppmvd during steady state and 12 ppmvd during non-steady state • 3 – 10 MW (operating < 877 hrs/yr, not listed above) – 9 ppmvd • 3 – 10 MW (operating ≥ 877 hrs/yr, not listed above) – 5 ppmvd • > 10 MW (simple cycle, operating < 200 hrs/yr, except as provided in Section 5.1.3.3) – 25 ppmvd • > 10 MW (simple cycle, operating >200 but no greater than 877 hrs/yr) – 5 ppmvd CO emission limits @15% O_2: • Units not identified below – 200 ppmv • General Electric Frame 7 – 25 ppmv • General Electric Frame 7 with Quiet Combustors – 52 ppmv	NOx limit @ 15% O_2, where Y = Manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen: • 0.0075*(14.4/Y)+F •0.0150*(14.4/Y)+F SO_2 limit @15% O2: • 0.015% by volume	NOx limit @ 15% O_2: • ≤ 50 MMBtu/hr – 42 ppm new, firing natural gas, electric generating • ≤ 50 MMBtu – 100 ppm new, firing natural gas, mechanical drive • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 25 ppm new, firing natural gas • >850 MMBtu/hr – 15 ppm new, modified, or reconstructed, firing natural gas • ≤ 50 MMBtu/hr – 96 ppm new, firing fuels other than natural gas, electric generating • ≤ 50 MMBtu/hr – 150 ppm new, firing fuels other than natural gas, mechanical drive • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 74 ppm new, firing fuels other than natural gas • >850 MMBtu/hr – 42 ppm new, modified, or reconstructed, firing

		lbs/MWhr or 9 ppmv • > 500 MMBtu/hr – 0.15 lbs/MWhr or 5 ppmv Low usage NOx emission limits (@ 15% O_2) for refinery fuel gas, waste gas or LPG: • < 50 MMBtu/hr – exempt • 50 - > 500 MMBtu/hr – N/A Low usage NOx emission limits (@ 15% O_2) for natural gas: • < 50 MMBtu/hr – exempt • 50 – 250 MMBtu/hr – 1.97 lbs/MWhr or 42 ppmv • > 250 – 500 MMBtu/hr – 1.17 lbs/MWhr or 25 ppmv • > 500 MMBtu/hr – 0.72 lbs/MWhr or 25 ppmv		• < 2 MW Solar Saturn gas turbine powering centrifugal compressor – 250 ppmv		fuels other than natural gas • ≤ 50 MMBtu/hr – 150 ppm modified or reconstructed • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 42 ppm modified or reconstructed, firing natural gas • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 96 ppm modified or reconstructed, firing fuels other than natural gas SO_2 limit: • 110 ng/J • 65 ng/J for turbines burning at least 50% biogas in a calendar month
Reporting	Annual emissions reporting and source testing. CEMS data every six months (Rule 218).	Source testing	None	Source testing	Semi- annual reports of excess emissions and monitor downtime	Semi- annual reports of excess emissions and monitor downtime. Annual performance test results.
Monitoring	A continuous in-stack NOx monitor for turbines with a capacity of 2.9 MW or greater. Periodic source testing for turbines with a capacity of < 2.9.	A continuous in-stack NOx monitor for turbines with a heat input rating equal to or greater than 150 MMBtu/hr and operate for more than 4000 hours in any 36-month period. Source test at least once per calendar year, not to exceed 15 months, for turbines that	Equipment which monitors control system operating parameters, elapsed time of operation, and continuous exhaust gas NOx concentration s for turbines with a rated	Continuous emissions monitoring equipment for NOx and CO or monitoring of operational characteristics recommended by the turbine manufacturer of emission control system supplier. Exhaust gas	A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or CEMS for stationary gas turbines using water or steam injection.	A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or continuous emission monitoring for stationary gas turbines using water or steam injection.

		operate more than 400 hours in any 12-month period and is not equipped with a continuous monitor. Source test every two calendar years, not to exceed 25 months, for turbines that operate 400 hours or less in any 12 month period.	output ≥ 10 MW and operated for more than 4000 hours in any one calendar year during the three years before April 6, 1995. Equipment which monitors control system operating parameters and elapsed time of operation for turbines with a rated output < 10 MW. Annual source testing.	NOx emissions monitoring system for turbines 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994. Annual source testing except for turbines operated < 877 hrs/yr, which are to be source tested biennially.	Monitor the total sulfur content of the fuel being fired.	Annual performance tests or continuous monitoring for turbines without water or steam injection. Monitor the total sulfur content of the fuel being fired.
Recordkeeping	Data monitoring records including CEMS and source tests, and operation, maintenance, service, and tuning records, maintained for five years	Daily operating log for low-usage exemption maintained for two years. Records of fuel consumption, output, and flow rates if using NOx limits expressed in lbs/MWhr.	Permit number, manufacturer, model, rating in MW, actual startup and shutdown time, daily hours of operation, cumulative hours of operation to date for the calendar year, actual daily fuel usage, emission test results, and maintenance records for two years. Additional records of exemptions.	Operating log, start-up and shutdown records, records of each bypass transition period and primary re-ignition period maintained for five years	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks
Fuel Restrictions	Liquid fuel	None	None	None	None	None

Table XVII: PR 1179.1 Comparative Analysis- Boilers

Rule Element	PR 1179.1	BAAQMD Regulation 9 Rule 7	SMAQMD Rule 411	SJVAPCD Rule 4320	Equivalent Federal Regulation
Applicability	Boilers, steam generators and process heaters over 400,000 Btu/hr fueled by digester gas or a digester gas blend and located at a POTW facility.	Industrial, institutional and commercial boilers, steam generators and process heaters with a rated heat input ≥1 MMBtu/hr.	Units (i.e., boilers, steam generators and process heaters) fired on gaseous or nongaseous fuels with a rated heat input capacity ≥1 MMBtu/hr.	Any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input > 5 million Btu per hour.	None
Requirements	NOx emission limits @ 3% O_2: • > 2MMBtu/hr – 15 ppm on or before date of adoption • ≤ 2 MMBtu/hr – 30 ppm on or before date of adoption CO Emission limit @ 3% O_2: 400 ppm	Digester gas NOx emission limit @ 3% O_2: 30 ppmv CO emission limit @3% O_2: 400 ppmv	NOx emission limits @ 3% O_2: • ≥ 1 and <5 MMBtu/hr input – 30 ppmvd • ≥5 and ≤20 MMBtu/hr input – 15 ppmvd • >20 MMBtu/hr input – 9 ppmvd CO emission limits @ 3% O_2: 400 ppmvd	NOx emission limits @3% O_2: • Units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas – 9 ppmv or 0.011 lb/MMBtu CO emission limit @3% O_2: 400 ppmv	None
Reporting	CEMS data every six months (Rule 218). Annual emissions reporting and source testing.	None	Annual tune-up verification report or verification of inactivity for low fuel usage units.	None	None
Monitoring	A continuous in-stack NOx monitor for boilers Rated heat input capacity > 40 MMBtu/hr and an annual heat input > 200 x 10^9 Btu per year. Source testing every 3-5 years for other boilers.	None	Accuracy testing once every calendar year for units with CEMS. Source testing: • > 20 MMBtu/hr – once every calendar year • ≥ 5 but <20 MMBtu/hr – once every second calendar year	CEMS or approved monitoring system. Source testing once every 12 months.	None
Recordkeeping	Monitoring data including CEMS, source tests, diagnostic emission checks, maintenance, service, and tuning records, and an operating log for five years.	Tune-ups and operating log for 24 months.	Monitoring data including CEMS, source tests, and portable analyzer checks for five years	Startup and shutdown for five years.	None