SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

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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 and 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 86 biogas fueled boilers, turbines, and engines, at 30 facilities will be affected by PR 1179.1. Oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compound (VOC) 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 NOx emission limits. Boilers, turbines less than 0.3 MW, and engines will be subject to NOx emission limitations that are the same as those contained in current applicable source-specific rules or current equipment permits. 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[1]. The cost-effectiveness for turbines to meet 18.8 ppm at rule adoption is $48,600 per ton of NOx reduced[2]. Facilities would also be required to revise equipment permits to reflect the applicability of PR 1179.1. Including the costs for permit revisions, the total cost-effectiveness to implement PR 1179.1 is approximately $50,000 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

[1] Reductions calculated are based on current permitted concentration emission levels and proposed emission limit.
[2] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests.

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 was 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

REGULATORY HISTORY

AFFECTED FACILITIES AND EQUIPMENT

PUBLIC PROCESS

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 and 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. Flaring excess gas is recognized as an important aspect of maintaining safety but it is preferred 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 associated with digester gas 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 characteristics of POTWs that required consideration throughout the rule development. These unique characteristics include the composition of the digester gas, the use of digester gas, the potential impacts of statewide legislation including Senate Bill (SB) 1383, and the challenges unique to public entities, including financial constraints and the public planning process.

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 for reducing NOx. To resolve this problem, facilities use 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 and the Public Planning Process

POTWs experience 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 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 1-2 lists the combustion equipment located at POTWs and applicable rules.

TABLE 1-1
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 30 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 recently amended source-specific rules. Table 1-2 contains the equipment affected by PR 1179.1.

TABLE 1-2
AFFECTED EQUIPMENT

Equipment Type	Number of Units
Boilers > 2 MMBtu/hr	
Digester gas	7
Dual fuel	26
Boilers ≤ 2 MMBtu/hr	
Digester gas	6
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 turbines located at a POTW will be contained in PR 1179.1. All combustion equipment permitted to fire only non-digester gas fuels will remain subject to source-specific rules, with the exception of turbines greater than or equal to 0.3 MW. Equipment at POTWs not affected by PR 1179.1, include emergency engines, flares, miscellaneous equipment, and most natural gas fired equipment (excluding turbines ≥ 0.3 MW). 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.

Applicability to Engines at POTWs

Initially during the rule development process, staff was proposing to keep engines subject to 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 and updated 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 to be 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 of waiving these fees. However, permitting fees are established in Regulation XIII and the request would require a separate rule amendment.

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 address key issues.

A Public Workshop was 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. In addition, staff has met several times with the affected stakeholders via remote communication to review the proposed rule language and to address outstanding issues.

CHAPTER 2: BARCT ASSESSMENT

INTRODUCTION

BARCT ANALYSIS APPROACH

Boilers ≤ 2 MMBtu/hr

Boilers > 2 MMBtu/hr

Turbines < 0.3 MW

Turbines ≥ 0.3 MW

SUMMARY OF BARCT EMISSION LIMITS

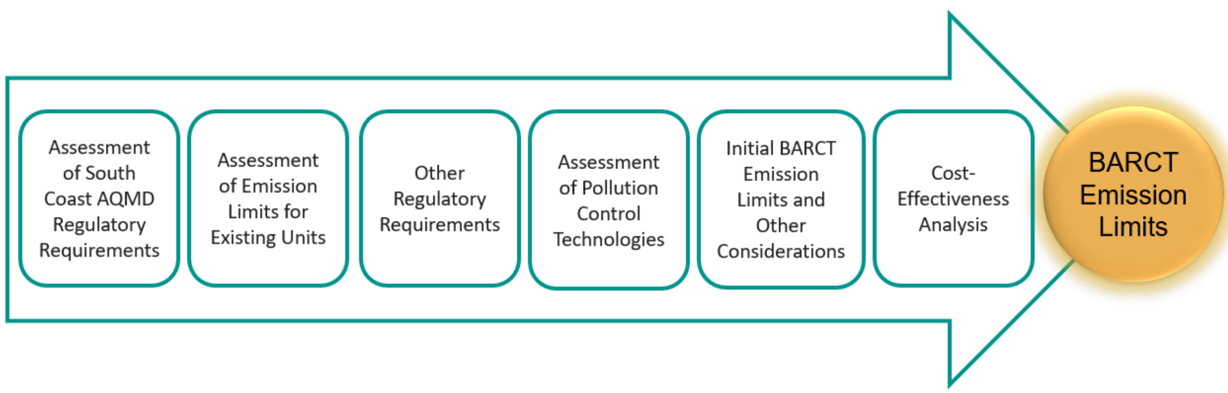
INTRODUCTION

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 were conducted only for digester gas fired boilers and turbines as part of rulemaking for PR 1179.1 because digester gas engines underwent a BARCT analysis under Rule 1110.2 and most of those engines[1] had effective dates beginning in January 1, 2017. Therefore, a BARCT assessment for digester gas engines was not conducted for this rulemaking. Similarly, natural gas turbines underwent a BARCT analysis in 2019 and a BARCT assessment for those turbines was not conducted during this rulemaking.

[1] Variances were granted for three facilities that provided extra time to comply with the emission limits in Rule 1110.2 or implement an alternative digester gas beneficial use project.

BARCT ANALYSIS APPROACH

Boilers ≤ 2 MMBtu/hr

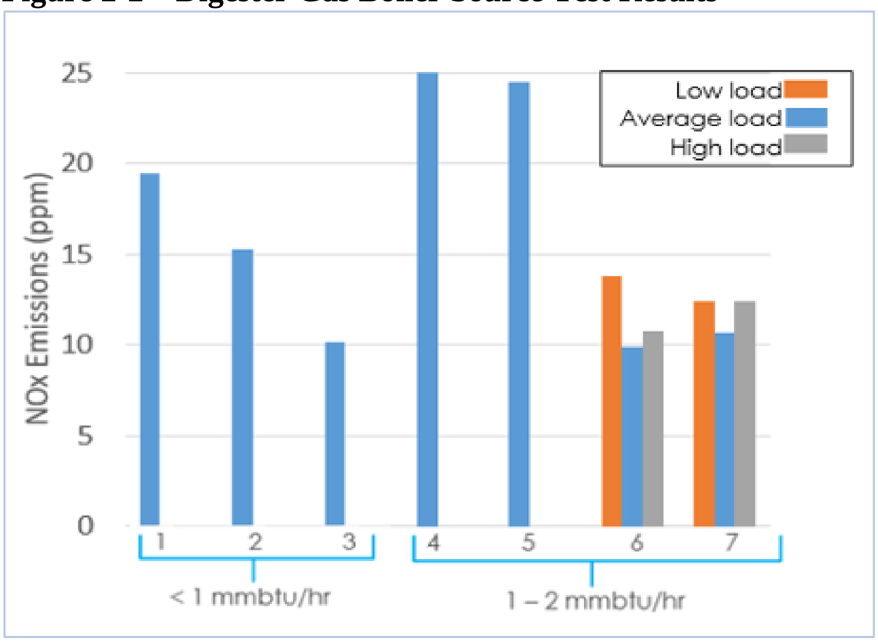
Assessment of South Coast AQMD Regulatory Requirements

There are 16 boilers ≤ 2 MMBtu/hr fired on digester gas within South Coast AQMD jurisdiction (6 digester gas, 10 dual fuel). The majority of these units are subject to individual permit limits. The permit limit for most of these units is 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 16 boilers and the 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 can be 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 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 combined with concerns expressed by facilities about 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. All boilers ≤ 2 MMBtu/hr surveyed with the exception of four units described above are already permitted at 30 ppm at 3 percent oxygen on a dry basis.

TABLE 2-1
INITIAL NOX EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL BOILERS ≤ 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption
Boilers ≤ 2 MMBtu/hr firing digester gas, digester gas and another fuel, or other fuel	30 ppm*

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

Cost-Effectiveness Analysis

For boilers currently permitted at 30 ppm at 3 percent oxygen on a dry basis, a cost-effectiveness analysis was not conducted for these units that will meet the proposed emission limit upon rule adoption. No costs were considered for boilers without a permitted NOx concentration limit to meet 30 ppm upon unit replacement, since replacing burner units is a normal part of business operations and would not incur additional costs.

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 2-2
PROPOSED BARCT EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL BOILERS ≤ 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption*	Limit Upon Burner or Boiler Replacement*
Boilers ≤ 2 MMBtu/hr firing digester gas, digester gas and another fuel, or other fuel	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

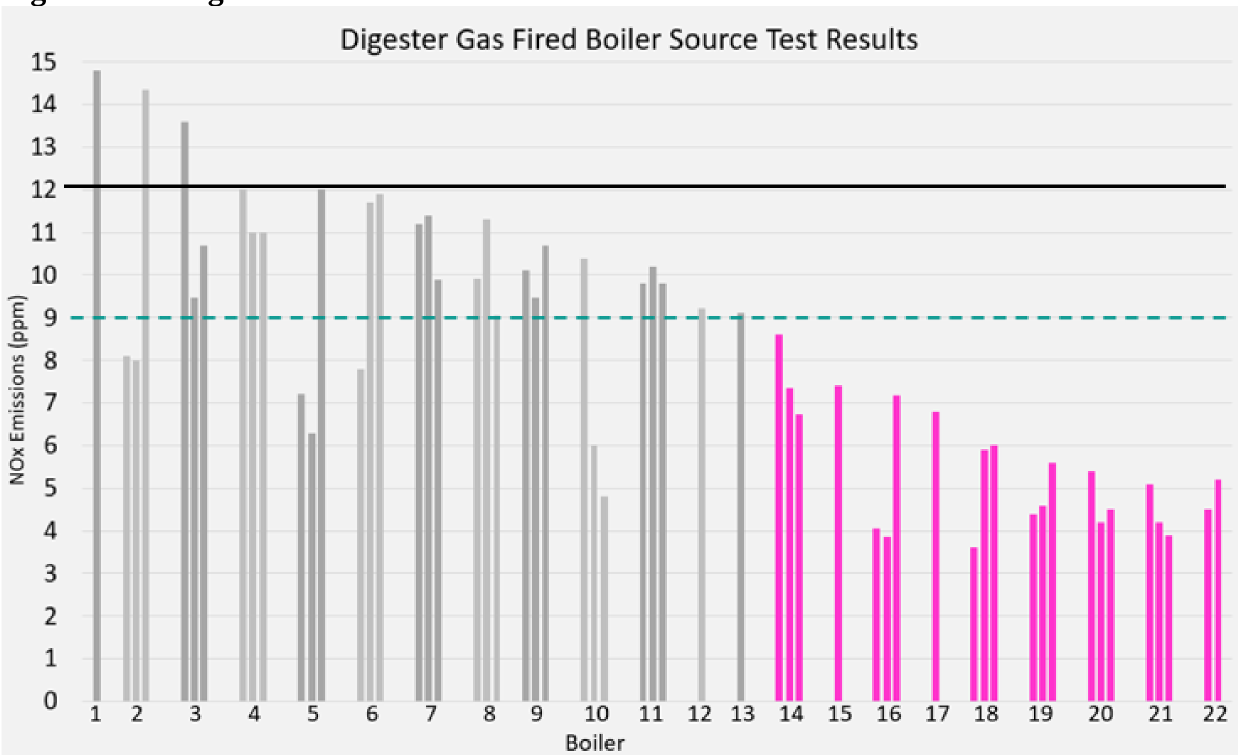
Assessment of South Coast AQMD Regulatory Requirements

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 approved percentage 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.*

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. Nevertheless, even with different source test protocols, results for digester gas fired boilers using South Coast AQMD protocols confirm BARCT at 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 higher 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 affect 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 proposed a 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 process, 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 facilities.

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 when achieved by requiring 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 2-4
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 firing at least 90% firing digester gas	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. The other 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 in operation 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 2-5
INITIAL NOX EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption*
Turbines < 0.3 MW in operation prior to May 3, 2013 firing digester gas, digester gas and natural gas, or natural gas	N/A
Turbines < 0.3 MW firing digester gas, digester gas and another fuel, or other fuel	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 2-6
PROPOSED BARCT EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit Upon Turbine Replacement*
Turbines < 0.3 MW in operation prior to May 3, 2013 firing digester gas,	N/A	N/A

digester gas and natural gas, or natural gas		
Turbines < 0.3 MW firing digester gas, digester gas and another fuel, or other fuel	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 2-7
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 available for the 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 more costly and less convenient than utility water. Storage sites and delivery are required for use of demineralized water. Utilizing water injection can be 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. Despite this, 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 more frequent catalyst replacements.

Within South Coast AQMD, SCR is currently used at a POTW with three digester gas turbines equipped with SCR, which were permitted in 2017. Those 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 operating 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 and low exhaust temperature, making it unsuitable for high pressure heat recovery steam generation.

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

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

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.

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 maintain.

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, requiring 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 for digester gas. 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 type, staff is not proposing a separate emission level for turbines without SCR.

TABLE 2-8
INITIAL NOX EMISSION LIMITS FOR DIGESTER GAS TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit effective on future compliance date*
Turbines ≥ 0.3 MW firing at least 60% percent digester gas	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 2-9
PROPOSED BARCT EMISSION LIMITS FOR DIGESTER GAS TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit Upon Turbine Replacement
Turbines ≥ 0.3 MW firing at least 60% percent digester gas	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 would be required to meet 18.8 ppm at 15 percent oxygen on a dry basis on or before rule adoption.

TABLE 2-10
EMISSION LIMITS AND COMPLIANCE SCHEDULE

Equipment Type	Limit at Rule Adoption*	Limit Upon Unit Replacement
Boilers ≤ 2 MMBtu/hr firing digester gas, digester gas and another fuel, or other fuel	30 ppm*	30 ppm*
Boilers ≤ 2 MMBtu/hr without permitted NOx concentration limits, firing digester gas, digester gas and another fuel, or other fuel	Permit Limit	30 ppm*
Boilers > 2 MMBtu/hr firing at least 90% digester gas	15 ppm*	BACT Limit
Turbines < 0.3 MW in operation after May 3, 2013 firing digester gas, digester gas and another fuel, or other fuel	9 ppm^	9 ppm^
Turbines ≥ 0.3 MW firing at least 60% digester gas	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

PROPOSED RULE STRUCTURE

PROPOSED RULE 1179.1

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Attachment 2) Boiler Tuning Procedure

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) Schedule for Permit Revisions
m) Exemptions
Attachment 1) I&M Plan Elements
Attachment 2) Boiler Tuning Procedure

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, located at a POTW that are permitted to fire digester gas, including dual fuel units that are permitted to fire digester gas and another fuel. PR 1179.1 also applies to all turbines ≥ 0.3 MW located at a POTW, regardless of the fuels the unit is permitted to fire, since Rule 1134 requirements (which regulates turbines) specifically excludes 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 produced by anaerobic decomposition of organic material.*

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.

- *DIGESTER GAS UNIT is any combustion equipment subject to this rule permitted to fire digester gas exclusively.*

  This definition was added to describe a type of unit that is applicable to PR 1179.1.

- *DUAL FUEL UNIT is any combustion equipment subject to this rule permitted to fire digester gas and another fuel.*

  This definition was added to describe a type of unit that is applicable to PR 1179.1.

- *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 applicable to PR 1179.1.

- *SHUTDOWN is the time period that begins when an operator reduces load and which ends in a period of zero fuel flow.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1179.1.

- *STARTUP is the time period that begins when a unit combusts fuel after a period of zero fuel flow and which ends when the unit reaches stable operating conditions.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1179.1.

- *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)(5) – Startup and Shutdown.

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

DIGESTER GAS AND DUAL FUEL BOILERS AND PROCESS HEATERS			
EQUIPMENT CATEGORY	NOx (ppm)[1]	CO (ppm)[1]	COMPLIANCE DATE
Rated heat input capacity > 2 MMBtu/hr and firing 90% digester gas or more[2]	15	400	On or before [*Date of Adoption*]
Rated heat input capacity > 2 MMBtu/hr and firing 100% natural gas	9		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 and averaged over 15 minutes.

2 Percent digester gas is based on the flowrates and higher heating values of the fuels.

The NOx and CO concentration limits are listed for units fired on 90 percent digester gas or more, based on higher heating values and flowrates of the fuels used, and 100 percent natural gas, 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

Any boiler that fires less than 90 percent digester gas would be required to use a weighted emission limit determined by Equation 1, in paragraph (d)(2). Since it is not expected that facilities would fire digester gas with a fuel other than natural gas, the weighted emission limit only applies to boilers that fire digester gas and natural gas simultaneously.

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 paragraph (d)(2), as specified in paragraph (m)(7) of this rule, and would meet 30 ppm at 3 percent oxygen on a dry basis upon burner or boiler replacement, regardless of fuel fired.
- 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 60 percent digester gas or more and 100 percent natural gas, along with the implementation schedule.

TURBINES			
EQUIPMENT CATEGORY	NOx (ppm)[3]	CO (ppm)[3]	COMPLIANCE DATE
Rating ≥ 0.3 MW and firing 60% digester gas[4] or more	18.8	130	On or before [*Date of Adoption*]
Simple cycle with rating ≥ 0.3 MW and firing 100% natural gas	2.5		On or before [*Date of Adoption*]
Combined cycle with rating ≥ 0.3 MW and firing 100% natural gas	2		On or before [*Date of Adoption*]
Rating < 0.3 MW and firing digester gas, digester gas with another fuel, or natural gas	9		On or before [*Date of Adoption*]

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

[4] Percent digester gas is based on volume averaged over a 24 hour period.

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 60 percent or more digester gas. Sixty percent was chosen because it reflects the current permit thresholds for the minimum use of digester gas for both of the affected facilities, and is based on volume averaged over a 24 hour period. Any unit that fires 100 percent natural gas would be required to meet the same BARCT emissions levels established in Rule 1134. Rule 1134 requires simple cycle turbines to meet 2.5 ppm at 15 percent oxygen on a dry basis and combined cycle turbines to meet 2 ppm at 15 percent oxygen on a dry basis. There are no units firing 100 percent natural gas at a POTW, currently.

Any turbine that fires less than 60 percent digester gas would be required to use a weighted emission limit determined by Equation 2, in paragraph (d)(3). Since it is not expected that facilities would fire digester gas with a fuel other than natural gas, the weighted emission limit only applies to turbines that fire digester gas and natural gas simultaneously.

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 digester gas or dual fuel turbines, more commonly referred to as microturbines, will be subject to the requirements of PR 1179.1 when firing digester gas, digester gas and another fuel, or the other fuel only. 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. Turbines less than 0.3 MW permitted to fire only non-digester gas fuels is not subject to this rule.

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

Digester gas engines or dual fuel engines that are fired on digester gas, digester gas and another fuel, or the other fuel only, 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. Engines located at a POTW permitted to fire only non-digester gas fuels such as natural gas would continue to comply with all requirements contained in Rule 1110.2 and would not be subject to PR 1179.1.

DIGESTER GAS AND DUAL FUEL ENGINES				
EQUIPMENT CATEGORY	NOx (ppm)[5]	CO (ppm)[5]	VOC (ppm)[6]	COMPLIANCE DATE
Engines > 50 bhp	11	250	30	On or before [*Date of Adoption*]

5 All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 15 minutes.

6 Parts per million (ppm) emission limit referenced at 15% volume stack gas oxygen on a dry basis, measured as carbon, and averaged over the sampling time required by the test method.

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 90 percent or more digester gas and 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 and flowrates. 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. Flowrate and units were added for clarity in determining the heat input value as required in Rules 1146 and 1146.1, Equations 1146-1 and 1146.1-1, respectively. Owners and operators of these units must comply with either the weighted emission limit or with the natural gas NOx limit.. The digester gas higher heating value used in the equation must be obtained using an approved procedure by the South Coast AQMD. Approved South Coast AQMD procedures include submitting digester gas samples for laboratory analyses and using portable monitoring devices. A representative sample of the facility's digester gas would be allowed as long as this same gas is sent to the subject boiler. The flowrates of the fuels used must be obtained using an approved non-resettable totalizing fuel flow meter. The flowrate must be obtained at the time compliance is determined and the digester gas sample used to obtain the higher heating value must be collected no earlier than 30 days before compliance is determined, to ensure there is accurate representation of the digester gas.

$$\text{Weighted Limit} = \frac{(CL_A \ x \ Q_A \ x \ V_A) + (CL_B \ x \ Q_B \ x \ V_B)}{(Q_A \ x \ V_A) + (Q_B \ x \ V_B)} \quad \text{(Equation 1)}$$

Where:

CL_A= compliance limit in Table 1 when firing 90% digester gas or more

Q_A = higher heating value of digester gas in Btu per standard cubic foot (scf)

V_A = flowrate of digester gas in scf per unit of time

CL_B = compliance limit in Table 1 when firing 100% natural gas

Q_B = higher heating value of natural gas in Btu per scf

Emission limits for turbines ≥ 0.3 MW that fire less than 60 percent digester gas simultaneously with natural gas – Paragraph (d)(3)

Turbines ≥ 0.3 MW that fire more than 40 percent natural gas and less than 100 percent natural gas are subject to a weighted emission limit calculated by Equation 2. The digester gas higher heating value used in the equation must be obtained using an approved procedure by the South Coast AQMD. Approved South Coast AQMD procedures include submitting digester gas samples for laboratory analyses and using portable monitoring devices. A representative sample of the facility's digester gas would be allowed as long as this same gas is sent to the subject turbine. The flowrates of the fuels used must be obtained using an approved non-resettable totalizing fuel flow meter. The flowrate must be obtained at the time compliance is determined and the digester gas sample used to obtain the higher heating value must be collected no earlier than 30 days before compliance is determined, to ensure there is accurate representation of the digester gas.

$$\text{Weighted limit} = \frac{\left((\mathrm{CL_A}+18.1) \text{ x } \mathrm{Q_A} \text{ x } \mathrm{V_A}\right) + (\mathrm{CL_B} \text{ x } \mathrm{Q_B} \text{ x } \mathrm{V_B})}{(\mathrm{Q_A} \text{ x } \mathrm{V_A}) + (\mathrm{Q_B} \text{x } \mathrm{V_B})} \quad \text{(Equation 2)}$$

Where:

CL_A = compliance limit in Table 1 when firing 60% digester gas or more

Q_A = higher heating value of digester gas in Btu per scf

V_A = flowrate of digester gas in scf per unit of time

CL_B = compliance limit in Table 1 when firing 100% natural gas

Q_B = higher heating value of natural gas in Btu per scf

V_B = flowrate of natural gas in scf per unit of time

Equation 2 adds a correction factor of 18.1 to account for the allowance of up to 40 percent natural gas to be fired when complying with 18.8 ppm at 15 percent oxygen on a dry basis.

Averaging Times for Units with CEMS – Paragraph (d)(4)

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)(5)

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 is necessary for the proper operation of the boiler for startup and not longer than 6 hours for startup or shutdown (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
- Boilers ≥ 5 – 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per month
- Boilers > 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per year

Maximum startup and shutdown requirements reflect current requirements in Rule 429. Boilers currently subject to Rule 1146 are required to comply with Rule 429. Since digester gas and dual fuel boilers would no longer be subject to Rule 1146, Rule 429 requirements were included in PR 1179.1. Facilities are required to submit a startup and shutdown schedule by January 1 of each year to the Executive Officer and notify the Executive Officer prior to each startup and shutdown event with the dates, times, and duration of the scheduled startup and shutdown and of any other process variables requested by the Executive Officer.

- Turbines without SCR: Startup cannot exceed the time at which control equipment is properly operating and cannot exceed 3 hours. Control equipment includes any mechanism that reduces NOx emissions for the purpose of meeting the emission limits of Table 1 or paragraph (d)(3), such as water injection or dry low emission systems.
- Turbines with SCR: Not longer than is necessary for the SCR to properly operate and not longer than 2 hours.
- 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)

Facilities are required to comply with the startup and shutdown requirements of PR 1179.1 upon adoption, as well as startup and shutdown requirements contained in a unit permit. In cases where permit requirements are more stringent than those in PR 1179.1, in order to comply with other rule or regulation requirements, the facility shall comply with the more stringent requirement.

<u>Prohibition of liquid fuel – Paragraph (d)(6)</u>

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 (m).

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	Elapsed Time Prior to Conducting Source Test[1]
Boilers ≥ 10 MMBtu/hr	Every 3 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	NOx, CO	At least 250 operating hours or at least 30 calendar days

Boilers < 10 MMBtu/hr and > 2 MMBtu/hr	Every 5 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		
Turbines with output capacity rating ≥ 2.9 MW	Every year from the date the previous source test was required, no later than the last day of the calendar month that the test is due		At least 40 operating hours or at least 7 calendar days
Turbines with output capacity rating < 2.9 MW	Every 3 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 later		
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	

[1] Elapsed 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. All equipment types would be required to source test no later than the last day of the calendar month that the source test is due.

Initial Source Testing - Paragraph (e)(2)

The owner or operator of any unit required to source test by Table 2, that has not conducted an initial source test for that unit, would be required to conduct a source test within 12 months from the adoption of PR 1179.1.

Source Test Protocol Submittal and Scheduling - Paragraph (e)(3)

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 subparagraph (e)(3)(A) 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. The owner or operator is allowed 90 days from the date the approval of the source test protocol was electronically distributed to conduct the source test.

Source Test Protocol Requirements - Paragraph (e)(4)

Contains requirements for the information required for submitting a protocol, in addition to further requirements pertaining to engines under subparagraph (e)(4)(A), which are consistent with current Rule 1110.2 requirements.

Source Test Date Notification - Paragraph (e)(5)

Contains requirements for notification of a scheduled source test.

Approved Contractor and Test Methods - Paragraph (e)(6):

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

Source Testing Facilities – Paragraph (e)(7)

Contains requirements for physical accommodations that allow for a source test to be conducted.

Operating Conditions During Source Testing for Boilers and Turbines - Paragraph (e)(8)

Contains requirements on conducting source tests for boilers and turbines in the as-found operating condition, and that no testing should be completed during periods of startup, shutdown, or under breakdown conditions. Also requires a minimum sampling time for boilers and turbines of 15 minutes.

Operating Conditions During Source Testing for Engines - Paragraph (e)(9)

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)(10)

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

Using Relative Accuracy Test Audits (RATAs) In Lieu of a Source Test - Paragraph (e)(11)

Contains an allowance for RATAs to be used in lieu of a source test, provided that the RATA is conducted within the same calendar that the source test is required. It should be noted that Proposed Rules 218.2 and 218.3 are currently under development and will contain enhanced provisions and requirements for units operating with CEMS that will apply to units covered by PR 1179.1.

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. As noted previously, 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

<table>
<tr><td>Turbines</td><td>Output capacity rating ≥ 2.9 MW</td><td>NOx</td></tr>
<tr><td rowspan="2">Engines</td><td>Output capacity rating ≥ 1000 bhp and operating more than 2 million bhp-hr per calendar year</td><td rowspan="2">NOx,
CO</td></tr>
<tr><td>Combined output capacity rating ≥1500 bhp and a combined fuel usage of >16 x 10^9 Btu per year, for engines at the same location[1]</td></tr>
</table>

[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, including flowrate of fuel gases, ratio of water or steam added, if applicable, elapsed time of operation, and turbine output in MW.

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 already applicable to these engines in Rule 1110.2.

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 combined emissions exceedances in any 12-month period as shown with a South Coast AQMD test using a portable analyzer or a source test, the owner or operator would 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 engine 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 exclusively natural gas and 1179.1 for digester gas would require one I&M plan for each rule.

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. If the diagnostic emission check frequency has been reduced to quarterly or every 2,000 unit operating hours, whichever occurs later, for boilers greater than or equal to 5 MMBtu/hr, or semi-annually or every 4,000 unit operating hours, whichever occurs later, for boilers great than 2 MMBtu/hr and less than 5 MMBtu/hr, the facility will continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption. Any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance would be a violation.

<u>Diagnostic Checks for Engines - Paragraph (h)(2)</u>

Provides diagnostic emission check requirements for engines, including testing frequency and additional requirements for lean-burn engine operators. If the diagnostic emission check frequency has been reduced to monthly or every 750 unit operating hours, whichever occurs later, the facility will continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption. 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)

Subparagraphs (i)(1)(A) and (i)(1)(B) provide recordkeeping requirements consistent with Rule 429 – Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen that boilers subject to Rule 1146 are currently complying with.

Recordkeeping for Turbines - Paragraph (i)(2)

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

Recordkeeping for Engines - Paragraph (i)(3)

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

Recordkeeping for Units Required to Conduct Source Test - Paragraph (i)(4)

Requires tuning and servicing records as well as records of the hours of operation of a unit since any tuning or servicing prior to conducting a source test.

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 recordkeeping 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.

TABLE 5

EXCESS EMISSION CONCENTRATION THRESHOLDS FOR BREAKDOWNS

Equipment Category	NOx (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000

[1] Corrected to 15% oxygen

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) – Schedule for Permit Revisions

Provides deadlines for permit applications to be submitted for revising equipment permits and I&M plans to reflect PR 1179.1. Facilities would only submit applications for equipment with permits that reference other source specific-rules no longer applicable once PR 1179.1 is adopted. Title V facilities would have until the next Title V permit renewal application is due to submit applications for each piece of equipment subject to PR 1179.1 and an I&M plan per facility, if applicable. Non-Title V facilities would submit applications by the proposed dates, depending on the type of equipment.

- Applications for each existing boiler > 2 MMBtu/hr would be required to be submitted on or before January 1, 2023
- Applications for each existing boiler ≤ 2 MMBtu/hr would be required to be submitted on or before July 1, 2023

- Applications for each existing engine and I&M plans for facility each facility with at least one engine subject to this rule would be required to be submitted on or before January 1, 2024
- Applications for each existing turbine would be required to be submitted on or before July 1, 2024

Subdivision (m) – Exemptions

Low-Use Boilers > 2 MMBtu/hr - Paragraph (m)(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 be exempt from the emission limits in Table 1 or paragraph (d)(2), but shall not operate the boiler in a manner that exceeds 30 ppm, provided the owner or operator follows the tune up procedures in Attachment 2 for that boiler. Any boiler that exceeds the 90,000 therm threshold is required to demonstrate compliance with the 15 ppm emission limit within 18 months of the exceedance.

Special Use Turbines - Paragraph (m)(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.

Non-Digester Gas Fired Boilers, Turbines < 0.3 MW, and Engines - Paragraph (m)(3)

Provides an exemption for units permitted to fire only non-digester gas fuels. Boilers at POTWs not permitted to fire any amount of digester gas would remain subject to the requirements of the Rule 1146 Series, depending on size (Rules 1146, 1146.1, 1146.2). Engines not permitted to fire any amount of digester gas would remain subject to the requirements of Rule 1110.2. Turbines less than 0.3 MW not permitted to fire any amount of digester gas are not subject to PR 1179.1.

Low-Use Engines - Paragraph (m)(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.

Exempted Engines - Paragraph (m)(5)

PR 1179.1 would not apply to laboratory engines used in research and testing purposes, engines operated for purposes of performance verification and testing of engines, auxiliary engines used to power other engines or gas turbines during start-ups, or portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.

Permit Exempt Turbines < 0.3 MW - Paragraph (m)(6)
Provides an exemption from rule requirements for turbines < 0.3 MW that were in operation before May 3, 2013 and are currently permit exempt.

Boilers Without Permitted NOx Concentration Limits - Paragraph (m)(7)
Provides an exemption for boilers without permitted NOx concentration limits. The boilers would be exempt from the emission limits in Table 1 or paragraph (d)(2). The emission limits in Table 1 and paragraph (d)(2) become effective upon a burner or boiler replacement.

Commissioning Period for Turbines and Engines – Paragraph (m)(8)
Provides an exemption from the emission limits in Table 1 or paragraph (d)(3) for the commissioning of new engines and turbines and specifies the commissioning period for each equipment type. Operators requesting this exemption must have these time periods as permit conditions.

Low-Use Boilers ≤ 2 MMBtu/hr Firing Natural Gas - Paragraph (m)(9)
Provides an exemption for boilers ≤ 2 MMBtu/hr that use less than 9,000 therms of natural gas, provided the natural gas usage is verified with an in line fuel meter or the annual operating hours are recorded by a timer and using a method described in subparagraphs (m)(9)(A) through (m)(9)(C) to calculate fuel use. These requirements are consistent with those in Rule 1146.2.

Engines Under Variances - Paragraph (m)(10)
Provides an exemption from the rule for five engines operated by San Bernardino Municipal Water Department currently operating under the variance issued by South Coast Air Quality Management District Hearing Board on December 20, 2018 for the term of the variance. Engines operating under this variance are expected to be decommissioned by the agency as part of implementing a Digester Gas Beneficial Use Program. The five engines remain subject to Rule 1110.2, in addition to the conditions of the variance, until the engines are removed from operation.

San Bernardino Municipal Water Department is implementing a fuel cell project that will utilize digester gas currently supplying the engines under the variance. Once the fuel cell project commences operation, the engines will no longer operate. However, if the engines continue to operate after the variance expires, the engines would no longer be exempt from PR 1179.1.

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.

Attachment 2 – Equipment Tuning Procedure for Forced-Draft Boilers, Steam Generators, and Process Heaters

Attachment 2 applies to boilers using the low-use exemption in paragraph (m)(1) and provides the procedure for tuning boilers, required at least twice per year by paragraph (m)(1). These parameters and procedures are consistent with those contained in Rules 1146 and 1146.1.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

EMISSION REDUCTIONS

COST-EFFECTIVENESS

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INCREMENTAL COST-EFFECTIVENESS

INTRODUCTION

POTW equipment is currently subject to source specific rules, 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 are currently subject to. In addition, PR 1179.1 contains provisions that reflect conditions on facility equipment permits. The emission limit proposed in PR 1179.1 will reduce emissions from three turbines located at one facility.

EMISSION REDUCTIONS

PR 1179.1 will result in emission reductions from 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

There six turbines located at two POTWs greater than or equal to 0.3 MW that fire either digester gas only or digester gas and another fuel. The emission limit proposed in PR 1179.1 will reduce emissions from three turbines located at one facility. The total baseline emissions for the facility impacted by the proposed emission limit are 149,156 pounds per year or 0.20 tons per day. The three turbines are permitted at 25 ppm at 15 percent oxygen on a dry basis. The baseline emissions for the facility operating the other three turbines are 96,854 pounds or 0.13 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 three turbines permitted at 25 ppm. The proposed emission limit would become effective upon rule adoption and the NOx emission reductions that would be achieved 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 4-1 and Table 4-2.

Table 4-1

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 4-2
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.

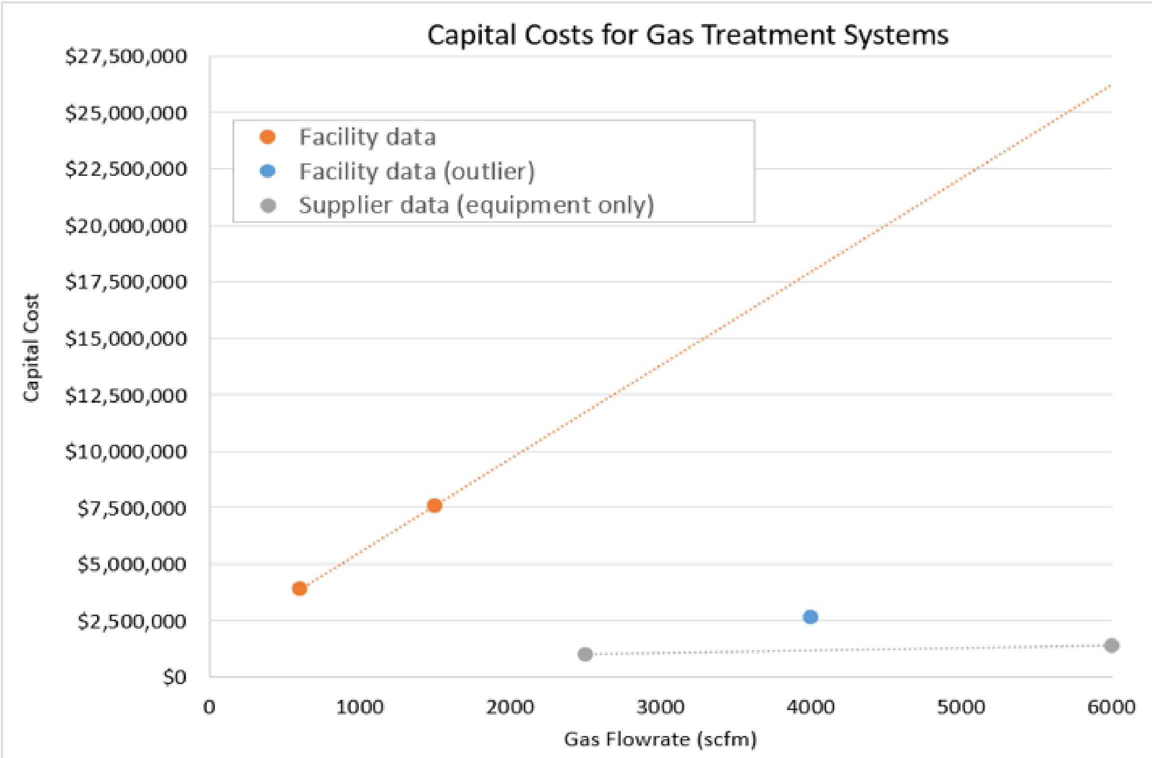
^ Annual costs provided by Facilities A and B did not include cost for catalyst due to new installations that have not required a catalyst replacement. An added annual cost of $33,000 (not shown in table) was added to Facility A's and Facility B's annual costs for catalyst. The added costs were included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

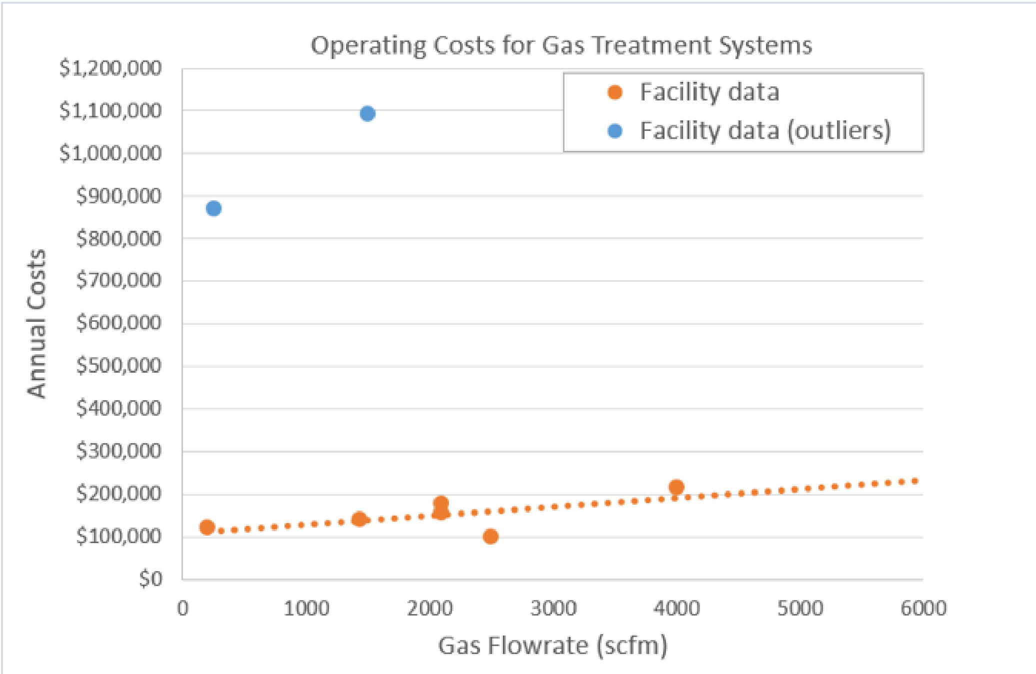
One outlier for cost information was identified and the data was not considered in determining capital costs. One supplier provided two cost estimates for two flowrates. The supplier provided only equipment costs. Figure 4-1 shows the data used to determine a capital cost for a gas treatment system in 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 data 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 turbine 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 4-3 summarizes of the cost-effectiveness to require existing turbines to meet each limit.

Table 4-3 – 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[1]	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

[1] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests and total 0.015 tpd.

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 4-4.

Table 4-4 – Cost-Effectiveness Analysis

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

Turbines ≥ 0.3 MW (To meet 18.8 ppm)	N/A	429,800	6.7 MM	0.05	48,600

Permit Revisions

Permits are required to be revised to reflect PR 1179.1 and to remove the references to former source-specific rules that would no longer apply to these sources under Rule 1179.1. Facilities would incur a one-time cost at the time that permit revisions are required, according to the schedule in subdivision (l) of PR 1179.1. The total combined cost for all facility permit revisions is $195,000. Table 4-5 contains the breakdown costs for permit revisions, based on Rule 301 – Permitting and Associated Fees.

Table 4-5 – Permit Revision Costs

Permit Revision Type	Cost (Non-Title V)	Cost (Title V)
Title V permit revision (per facility)	N/A	$1,518.26
Change of Conditions (per engine)	$4319.40	$5,412.63
Administrative Change (per equipment)	$962.75	$1,206.41
I&M Plan (per applicable facility w/engines)	$725.60	$909.25

Total Cost-Effectiveness of PR 1179.1

The cost-effectiveness to implement PR 1179.1 is $50,054 per ton of NOx reduced. Costs include the cost for three turbines at one facility to meet 18.8 ppm and all facilities with equipment permits that reference other source-specific rules, to revise equipment permits to reflect PR 1179.1.

SOCIOECONOMIC ASSESSMENT

California Health & Safety Code §40440.8 requires a socioeconomic impact assessment for proposed and amended rules resulting in significant impacts to air quality or emission limitations. This assessment shall include affected industries, range of probable costs, cost effectiveness of control alternatives, and emission reduction potential.

During the rulemaking for the December 2018 amendments for Rule 1146 Series, staff recommended to separate provisions for combustion equipment at Publicly Owned Treatment Works Facilities (POTWs). Proposed Rule 1179.1 - NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (PR 1179.1) was developed to establish BARCT requirements for combustion equipment located at POTWs using digester gas.

Proposed Rule 1179.1 would affect 30 POTW facilities with a total of eighty-six biogas fueled boilers, turbines, and engines. These facilities belong to the North American Industrial Classification Codes (NAICS) 2213 (Water, Sewage, and Other Systems) and 5622 (Waste Treatment and Disposal). Out of these 30 facilities, six are located in Los Angeles County, seven each in Orange and San Bernardino counties, and 10 in Riverside County.

Proposed Rule 1179.1 applies to combustion equipment used at POTWs. Specifically, PR 1179.1 contains emission limits on boilers, turbines, and engines at POTWs. Many of the emissions limits within PR 1179.1 are consistent with limits set in existing source specific rules (e.g., Rule 1146 and 1110.2) or equipment permits, and the boilers, engines, and turbines at POTWs already meet those limits. However, PR 1179.1 will require turbines greater than or equal to 0.3 MW to meet new, lower emission limits.

Of the 86 biogas-fueled boilers, turbines, and engines affected by PR 1179.1, only three turbines at one facility are expected to incur additional compliance costs associated with the PR 1179.1 requirements. Compliance costs for the three turbines above 0.3 MW are expected due to increased water injection and are estimated at $429,600 ($143,200 per turbine) annually.[5] In addition, facilities will incur a one-time cost to reconcile permits and comply with the PR 1179.1 requirements. The total estimated one-time cost for all facility permit revisions is estimated at $195,000,[6] and accounts for both Title V and non-Title V equipment permit revisions. The annualized cost of these permit revisions at four percent real interest rate is estimated at $23,985. As such, the estimated total annual compliance cost from PR 1179.1 is estimated at $453,585.

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 0.015 tpd. All other equipment will continue to comply with current emission limits. The cost-effectiveness of PR 1179.1, including the permit revisions, is estimated at $50,000 per ton of NOx reduced based on current concentration emission levels of the turbines as demonstrated in recent source tests.

The estimated total annual compliance costs from PR 1179.1 ($453,585) is estimated to be less than one million dollars annually. It has been a standard practice for South Coast AQMD's socioeconomic impact assessments that, when the annual compliance cost is less than one million current U.S. dollars annually, the Regional Economic Models Inc. (REMI)'s Policy Insight Plus Model is not used to simulate jobs and macroeconomic impacts, as is the case here. This is because the resultant impacts would be too small relative to the baseline regional economy to reliably determine any impacts from the modeling analysis.

[5] The cost figure of $143,200 was calculated using an average of two estimates provided by the facility affected by PR 1179.1 limits and a cost estimate provided by a demineralized water supplier.

[6] Title V facilities have a Title V revision cost of $1,518.26 (per facility). Each piece of permitted equipment at Title V facilities requiring a Change of Conditions permit revision will cost $5,412.63. Each piece of permitted equipment at non-Title V facilities requiring a Change of Conditions permit revision will cost $4,319.40. Facilities with permitted equipment requiring an Inspection & Monitoring plan will cost $909.25 per Title V facility and $725.60 per non-Title V facility. All other equipment requires an Administrative Change permit revision at a cost of $1,206.41 per piece of equipment at Title V facilities and $962.75 per piece of equipment at non-Title V facilities.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ASSESSMENT

PR 1179.1 is considered a "project" as defined by the California Environmental Quality Act (CEQA) and the South Coast AQMD is the designated lead agency. Pursuant to South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l); codified in South Coast AQMD Rule 110) and CEQA Guidelines Section 15070, the South Coast AQMD has prepared an Environmental Assessment (EA) with less than significant impacts for PR 1179.1, which is a substitute CEQA document, prepared in lieu of a Negative Declaration. A Draft EA has been released for a 30-day public comment and review period from August 12, 2020 to September 11, 2020. If comments are submitted, the letters and responses to comments will be incorporated into the Final EA which will be included as an attachment to the Governing Board package. Prior to making a decision on the adoption of PR 1179.1, the South Coast AQMD Governing Board must review and certify the Final EA, including responses to comments, as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting PR 1179.1.

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 its meaning can be easily understood by the persons directly affected by it.

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. See Table 4-6 below.

Table 4-6: 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: Digester gas and dual fuel turbines < 0.3 MW and turbines ≥ 0.3 MW..	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 60% digester gas or more – 18.8 ppm on or before date of adoption • Simple cycle ≥ 0.3 MW firing	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	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 ≥	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	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	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

	100%natural gas- 2.5 ppm on or before date of adoption • Combined cycle ≥ 0.3 MW firing 100% % natural gas- 2 ppm on or before date of adoption • < 0.3 MW gas- 9 ppm on or before date of adoption CO emission limit @15% O_2: 130 ppm	• > 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 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	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	• 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 • < 2 MW Solar Saturn gas turbine powering centrifugal compressor – 250 ppmv	SO_2 limit @15% O2: • 0.015% by volume	• > 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 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

		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				• > 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	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 all turbines.	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 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.	Equipment which monitors control system operating parameters, elapsed time of operation, and continuous exhaust gas NOx concentrations for turbines with a rated 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	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 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	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. Monitor the total sulfur content of the fuel being fired.	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. Annual performance tests or continuous monitoring for turbines without water or steam injection. Monitor the total sulfur content of the fuel being fired.

			system operating parameters and elapsed time of operation for turbines with a rated output < 10 MW. Annual source testing.	source testing except for turbines operated < 877 hrs/yr, which are to be source tested biennially.		
Recordkeeping	Maintain and keep records of CEMS data, source test reports, diagnostic emission checks, operating hours, maintenance, service, and tuning 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

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments relative to ozone, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control options as compared to the next less expensive control option.

Incremental cost-effectiveness is calculated as follows:

Incremental cost-effectiveness = $(C_{alt} – C_{proposed}) / (E_{alt} – E_{proposed})$

Where:

$C_{proposed}$ is the present worth value of the proposed control option;
$E_{proposed}$ are the emission reductions of the proposed control option;
C_{alt} is the present worth value of the alternative control option; and
E_{alt} are the emission reductions of the alternative control option

The proposed project would require one facility to meet 18.8 ppm at 15 percent oxygen on a dry basis on three turbines. The next progressively more stringent potential control option would be to require turbines to meet 5 ppm at 15 percent oxygen on a dry basis and would affect two facilities and a total of six turbines. To meet 5 ppm, one facility would be required to implement SCR on their existing turbines. The other facility would be required to replace their turbines with lower emitting turbines to meet 5 ppm.

Incremental cost-effectiveness = ($160,832,987 – $6,712,430) / (1,791 – 138) = $93,237 per ton of NOx reduced

The incremental cost analysis presented above demonstrates that the alternative control option is not viable when compared to the control strategy of the proposed amendments.

APPENDIX A – LIST OF AFFECTED FACILITIES

Table A-1: Facilities Affected by PR 1179.1

ID	Facility Name
20252	Banning City Wastewater Treatment Plant
2537	Corona City Department of Water & Power
7417	Eastern Municipal Water District
19159	Eastern Municipal Water District
1703	Eastern Municipal Water District
13088	Eastern Municipal Water District
9163	Inland Empire Utilities Agency
1179	Inland Empire Utilities Agency
147371	Inland Empire Utilities Agency
3513	Irvine Ranch Water District
800214	LA City Sanitation Bureau
10245	LA City Terminal Island Treatment Plant
800236	LA County Sanitation District
22674	LA County Sanitation District
94009	Las Virgenes Municipal Water District
17301	Orange County Sanitation District
29110	Orange County Sanitation District
5756	Redlands City Wastewater Treatment Plant
12923	Rialto City
9961	Riverside City Water Quality Control
11301	San Bernardino Municipal Water Department San Clemente City
20237	San Clemente City
51304	Santa Margarita Water District
181040	Santa Margarita Water District
13433	South Orange County Wastewater Authority
3966	South Orange County Wastewater Authority
10198	Valley Sanitation District
118526	Western Municipal Water District
111176	Western Riverside County Regional Wastewater Authority Treatment Plant
50402	Yucaipa Valley Water District

APPENDIX B – RESPONSES TO PUBLIC COMMENTS

Comment: PR 1179.1 should include a definition for “thermal stabilization period” and allow 2 hours for this period during startup, for cogeneration and combined cycle turbines.

Response: Staff included a 3-hour startup period for turbines ≥ 0.3 MW without SCR to allow sufficient time for the thermal stabilization period and/or any other startup mechanisms required for the turbine to reach stable conditions.

Comment: PR 1179.1 needs to specify how 40% natural gas is defined for the turbine emission limits.

Response: Staff revised the 18.8 ppm at 15% oxygen on a dry basis turbine emission limit to apply to any turbine ≥ 0.3 MW firing at least 60% digester gas. The rule specifies that 60% digester gas is based on volume averaged over a 24-hour period.

Comment: Turbines cannot meet natural gas emission limits when firing digester gas and more than 40% percent natural gas. Rule should have a weighted emission limit for turbines ≥ 0.3 MW firing less than 60% digester gas (more than 40% natural gas).

Response: Staff has included a provision for a weighted emission limit for turbines ≥ 0.3 MW firing more than 40% natural gas and less than 100% natural gas. Turbines firing 100% natural gas would be required to meet the natural gas NOx emission limit.

Comment: It is unclear what emission limits in Rules 1146 and 1146.1 dual fuel boilers are subject to when firing 100% natural gas.

Response: Staff has included dual fuel boilers that can fire 100% natural gas in the applicability of PR 1179.1. The emission limits for dual fuel boilers are contained in Table 1 and include the emission limit when firing 100% natural gas.

Comment: Throughout district rules, it is not clearly communicated that different rules and programs have different source test requirements.

Response: Source test requirements contained in PR 1179.1 are specific to PR 1179.1. Source test requirements contained in other rules and programs apply to the specific rule or program in which the requirements are contained. Facilities are required to meet all applicable requirements in across all applicable rules and programs.

Comment: PR 1179.1 does not include a provision currently in 1110.2 that allows a facility with engines at the same location with a combined output capacity rating of 1500 bhp or greater and a combined fuel usage of > 16 x 10^9 Btu per year (higher heating value) to comply with I&M plan requirements in lieu of installing a CEMS.

Response: Staff has included this provision to reflect the language currently in Rule 1110.2.

Comment: PR 1179.1 language pertaining to source test protocol submittal requirements does not clearly state when a subsequent source test protocol is required to be submitted for approval.

Response: Staff revised the rule language to clearly state when a subsequent source test protocol would be required for units subject to a previously approved protocol. Subsequent source test protocols would only be required if the unit has been altered in a manner that requires a permit alteration, if emission limits for the unit have changed since the previous source test, or if a new protocol is requested by the Executive Officer.

Comment: PR 1179.1 should allow Title V permit revisions to occur on the same cycle as Title V permit renewals.

Response: Staff has included a schedule for permit revisions that allows for Title V permit revisions to occur on the same cycle as Title V permit renewals.