SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report
Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills

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Deputy Executive Officer
Planning, Rule Development, and Area Sources
Philip M. Fine, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Susan Nakamura

Planning and Rules Manager
Planning, Rule Development, and Area Sources
Michael Morris

Author:	Isabelle Shine – Air Quality Specialist
Co-Author:	Melissa Gamoning – Air Quality Specialist Brian Vlasich – Air Quality Specialist
Contributors:	John Anderson – Air Quality Analysis & Compliance Supervisor Shah Dabirian – Program Supervisor Monica Fernandez-Neild – Senior Air Quality Engineer Glenn Kasai – Senior Air Quality Engineer Huy Anh Ngoc Le – Air Quality Engineer II Barbara Radlein – Program Supervisor Kendra Reif – Air Quality Specialist Dipankar Sarkar – Program Supervisor Angela Shibata – Supervising Air Quality Engineer Bill Welch – Source Testing Manager Mike Wickson – Senior Air Quality Engineer Lisa Wong – Air Quality Specialist
Reviewed By:	Rodolfo Chacon – Air Quality Specialist Karin Manwaring – Senior Deputy District Counsel Kevin Orellana – Program Supervisor William Wong – Principal Deputy District Counsel

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Supervisor, Second District
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<u>EXECUTIVE OFFICER:</u>

WAYNE NASTRI

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EXECUTIVE SUMMARY

Organic waste is deposited in municipal solid waste (MSW) landfills where it decomposes with the aid of methane-producing bacteria. This process results in a byproduct called landfill gas, a form of biogas. Combustion of landfill gas can be used to generate electricity at MSW landfills. Alternatively, raw landfill gas can be sold to landfill gas to energy (LFGTE) facilities, which process landfill gas to generate electricity for sale. Landfill gas differs from other process gases because it contains unique contaminants which can damage combustion equipment and impact the effectiveness of air pollution control equipment.

During the rulemaking for other source-specific regulations, South Coast AQMD staff received comments from the affected industry describing the unique challenges associated with the combustion of biogas that are different than the combustion of natural gas. Staff recommended to separate combustion equipment located at MSW landfills and LFGTE facilities into its own industry-specific regulation. Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills (PR 1150.3) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for boilers, process heaters, and turbines located at MSW landfills and LFGTE facilities using exclusively landfill gas or a combination of landfill gas and natural gas. PR 1150.3 also contains monitoring, reporting, and recordkeeping provisions applicable to MSW landfills and LFGTE facilities.

A total of twenty-one biogas fueled boilers and turbines, at seven facilities, will be affected by PR 1150.3. Through the rulemaking process, staff considered including landfill gas engines. Based on input from MSW landfills and LFGTE facilities, landfill gas engines were not included in PR 1150.3 and will continue to be regulated under Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines.

PR 1150.3 was developed through a public process. Five Working Group meetings were held on: March 21, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and August 12, 2020. Working Group meetings included representatives from affected facilities, equipment suppliers, environmental and community groups, other agencies, consultants, and interested parties. The purpose of the Working Group meetings was to discuss details of the proposed rule and to listen to concerns and issues with the objective to build consensus and resolve key issues.

In addition, a Public Workshop was held on October 7, 2020. The purpose of the Public Workshop was to present the proposed rule language to the general public and stakeholders and to solicit comment. Staff has also conducted multiple site visits as part of this rulemaking process and has met with individual facility operators.

CHAPTER 1: BACKGROUND

BACKGROUND

A municipal solid waste (MSW) landfill is an entire disposal facility in a contiguous geographical space where solid waste is placed in or on land. The organic waste deposited in MSW landfills decomposes with the aid of methane-producing bacteria. This process results in a byproduct called landfill gas, a form of biogas. Landfill gas can be captured in wells and processed to generate electricity sold directly to utilities. Alternatively, raw landfill gas can be sold to LFGTE facilities, which process landfill gas to generate electricity for sale. Landfill gas differs from other process gases because it contains unique contaminants which can damage equipment used in energy production.

During the rulemaking for the December 2018 amendments to 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), staff received comments from industry representatives describing the unique challenges with biogas that are different than natural gas. As a result, staff recommended a separate rulemaking for combustion equipment at MSW landfills, and publicly owned treatment works (POTWs), as POTWs have similar challenges MSW landfills. Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills (PR 1150.3) establishes Best Available Retrofit Control Technology (BARCT) requirements for boilers, process heaters, and turbines located at MSW landfills and LFGTE facilities using landfill gas or that use a combination of landfill gas and natural gas. PR 1150.3 also contains monitoring, reporting, and recordkeeping provisions applicable to MSW landfills and LFGTE facilities in one rule. Staff identified characteristics of MSW landfills and LFGTE facilities that are unique to such facilities. These characteristics include the properties of landfill gas and financial considerations. Throughout the rulemaking process, staff considered including internal combustion engines that are fueled by landfill gas. However, based on input from owners and operators at MSW landfill and LFGTE facilities, internal combustion engines were not included in PR 1150.3 and will continue to be regulated under Rule 1110.2 – Emissions from Gaseous- and Liquid- Fueled Engines (Rule 1110.2).

Landfill Gas

Landfill gas has different properties than natural gas. For example, landfill gas has a lower energy content or Btu content (higher heating value) than that of natural gas. Btu content has been reported in South Coast AQMD Annual Emission Reports in the range of 295-841 Btu/scf, whereas natural gas has a higher heating value of approximately 1050 Btu/scf. The energy content of landfill gas typically declines as the landfill closes.

The composition and volume of landfill gas also changes over time. Initially, aerobic bacteria decompose organic waste and produce CO_2 as a byproduct. After oxygen is depleted, anerobic bacteria continues to breakdown organic waste, and methane and CO_2 production become relatively steady. After a landfill stops accepting waste, there is a finite amount of material to decompose and produce landfill gas. At which point, the volume and quality of landfill gas declines.

Another significant difference between landfill gas and natural gas is the presence of contaminants such as siloxanes and hydrogen sulfide. Siloxanes are a type of organosilicon compound which exists in many cosmetic, personal and household products. Products containing siloxanes are deposited at landfills and decompose alongside other organic wastes. The presence of siloxanes in landfill gas can affect combustion processes such that when siloxane compounds are combusted, silicon dioxide is formed. Silicon dioxide is a glass-like compound that forms deposits on combustion equipment, increasing maintenance and if not maintained, causes damage to combustion equipment. Another complication of siloxanes is the impact on post combustion control equipment, specifically, selective catalytic reduction (SCR) units. Siloxanes can deactivate the SCR catalysts, reducing SCR effectiveness. To resolve this problem, equipment with SCRs must treat the gas to remove siloxanes before combustion. Inadequate cleaning of the landfill gas could result in more operating and maintenance costs.

Financial Considerations

MSW landfills are essential public services which have structured procurement processes. Projects require approval from governing bodies which may be by a city council, a board of directors, or a county board of 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. Even private entities that lease the gas from MSW landfills need appropriate approvals. To recover costs of implementing a control project, MSW landfills may attempt to increase utility rates for the consumer but public resistance to increases and other political pressures can make it difficult for MSW landfills to impose.

MSW landfills often sell excess electricity and raw landfill gas to utilities and LFGTE facilities, respectively. These gas to energy contracts, also known as power purchase agreements, can last for decades. A control project implemented during a power purchase agreement may not be cost-effective if the agreement is not renewed and there are stranded assets.

REGULATORY HISTORY

Combustion equipment located at MSW landfills and LFGTE facilities are currently regulated under the following source specific rules to reduce NOx emissions. NOx and CO emissions from boilers, process heaters, and steam generators are currently regulated under Rules 1146, 1146.1, and 1146.2. Rules 1146 and 1146.1 include emission limits for all fuels, including landfill gas. Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134) was amended on April 5, 2019 and excluded turbines located at landfills or turbines fueled by landfill gas considering that PR 1150.3 was in development. Table 1-1 lists the combustion equipment located at MSW landfills and LFGTE facilities and applicable rules.

TABLE 1-1
TYPICAL NOx RULES APPLICABLE TO COMBUSTION EQUIPMENT AT MSW LANDFILLS AND LFGTE FACILITIES

Equipment	South Coast AQMD Rule	General Provisions
Boilers > 2 MMBtu/hr	Rules 1146 and 1146.1 (all fuels)	NOx and CO emission limits, source testing, CEMS, monitoring, reporting, recordkeeping
Boilers ≤ 2 MMBtu/hr	Rules 1146.2 (natural gas only). No requirements for boilers ≤ 2 MM Btu/hr using landfill gas	NOx and CO emission limits reporting, recordkeeping
Internal combustion engines > 50 bhp	Rule 1110.2 – Emissions from Gaseous- and Liquid- Fueled Engines (all fuels)	NOx, VOC, CO emission limits, source testing, CEMS, monitoring, reporting, recordkeeping
Non-refinery flares	Rule 1118.1 – Control of Emissions from Non-Refinery Flares	NOx and VOC emission limits for non-refinery flares, source testing, monitoring, reporting, recordkeeping
Turbines	Currently no source specific rule for turbines ≥ 0.3 MW at landfills or those fueled with landfill gas	N/A

AFFECTED FACILITIES AND EQUIPMENT

Based on permitting data, seven MSW landfills and LFGTE facilities were identified that meet the applicability requirements of PR 1150.3. There are 3 boilers, 14 turbines rated ≥ 0.3 MW, and 4 turbines rated < 0.3 MW, fueled by landfill gas at these facilities. Table 1-2 contains the equipment affected by PR 1150.3.

TABLE 1-2
AFFECTED EQUIPMENT

Equipment Type	Number of Units
Boilers	
Landfill gas	3
Turbines ≥ 0.3 MW	
Landfill Gas	11
Dual Fuel	3
Turbines < 0.3 MW	
Landfill gas	4

Rule 1134 does not apply to any turbine located at a landfill or any turbine fueled by landfill gas. Currently, turbines located at MSW landfills or fueled by landfill gas are not subject to any rule. Provisions for landfill gas and other liquid and gaseous fueled turbines will be contained in PR

1150.3. All combustion equipment permitted to fire only non-landfill gas fuels will remain subject to source-specific rules, with the exception of turbines rated greater than or equal to 0.3 MW. Other equipment at MSW landfills or LFGTE facilities will not be affected by PR 1150.3. Emergency engines, flares, and most natural gas fired equipment (excluding turbines ≥ 0.3 MW) will be subject to existing source-specific rules and will not be subject to PR 1150.3. Flares located at MSW landfills and LFGTE facilities were assessed as part of the January 4, 2019, rulemaking for Rule 1118.1 – Control of Emissions from Non-Refinery Flares and will remain subject to Rule 1118.1.

A facility subject to PR 1150.3 that meets the applicability requirements of Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, would be subject to Rule 1135. Staff evaluated existing facilities and equipment during the PR 1150.3 rulemaking. Currently, there are no PR 1150.3 affected facilities that meet the applicability requirements of Rule 1135.

Applicability to Engines

Biogas engines, including landfill gas fired engines, are currently regulated by Rule 1110.2 and were analyzed in the 2012 Rule 1110.2 technology assessment. During the initial PR 1150.3 working group meetings, some stakeholders expressed a preference to include engines in PR 1150.3.

In subsequent working group meetings, staff discussed additional permitting fees associated with the potential inclusion of engines in PR 1150.3. Permitting fees for engines tend to be higher than other combustion equipment due to the structure of engine permits as engine permits reference specific rule provisions and require Inspection and Maintenance (I and M) plans. Staff surveyed operators with landfill gas engines to ascertain if operators would prefer complying with Rule 1110.2 or pay additional permitting fees to move the engine requirements under PR 1150.3.

Surveys were sent to three facilities identified to have non-emergency internal combustion engines subject to Rule 1110.2. Two of three facilities responded. The two facilities did not support including engines in PR 1150.3. Based on the survey results, engines at landfills and LFGTE facilities will not be subject to PR 1150.3 and will continue to be subject to Rule 1110.2.

PUBLIC PROCESS

The development of PR 1150.3 was conducted through a public process. Five Working Group meetings were held on: March 21, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and August 12, 2020. Working Group meetings included representatives from affected facilities equipment suppliers, environmental and community groups, other agencies, consultants, and interested parties. The purpose of the Working Group meetings was to discuss details of proposed amendments and to listen to concerns and issues with the objective to build consensus and resolve key issues.

In addition, one Public Workshop was held on October 7, 2020. The purpose of the Public Workshop was to present the proposed rule language to the general public and to stakeholders and to solicit comment. Staff has also conducted multiple site visits as part of this rulemaking process and has met with individual facility operators.

CHAPTER 2: BARCT ASSESSMENT

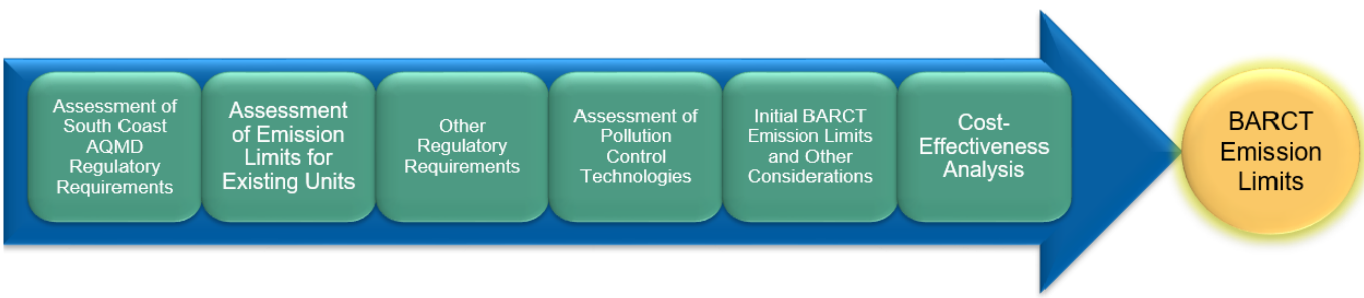
INTRODUCTION

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

"… an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

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

Figure 2-1 — BARCT Assessment Process



BARCT assessments were conducted for landfill gas fired boilers and turbines as part of the rulemaking for PR 1150.3.

BARCT ANALYSIS APPROACH

Assessment of South Coast AQMD Regulatory Requirements

<u>Boilers and Process Heaters</u>
South Coast AQMD Rules 1146 and 1146.1 require boilers and process heaters to meet a NOx emission limit of 25 ppmv at 3 percent oxygen on a dry basis when firing landfill gas.

Turbines

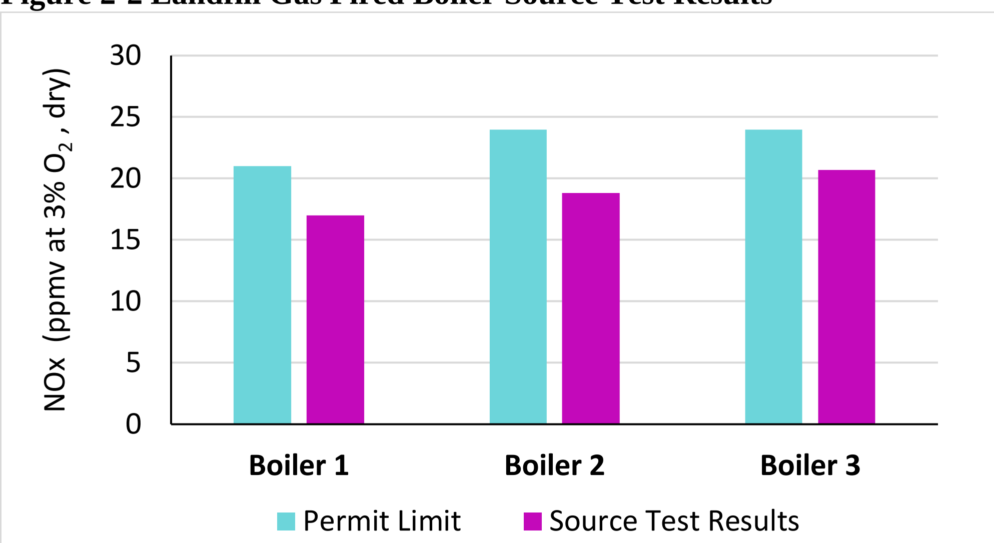
There is currently no South Coast AQMD rule that establishes a NOx limit for turbines located at landfills or fueled by landfill gas. Under Rule 219 – Equipment Not Requiring a Written Permit Pursuant to Regulation II, turbines with a rated maximum heat input capacity of 3.5 MMBtu/hr or less are exempt from permitting provided that the cumulative power output of all turbines at a facility is less than 2 MW. To qualify for this exemption, the turbines must be certified by the state of California at the time of manufacture or operated prior to May 3, 2013 and be registered under Rule 222 – Filing Requirements for Specific Emission Sources Not Requiring a Written Permit Pursuant to Regulation II. Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines, which applies to stationary gas turbines rated 0.3 MW and greater, excludes stationary gas turbines located at landfills or fueled by landfill gas.

Assessment of Emission Limits for Existing Units

Boilers and Process Heaters

There are three permitted landfill gas fired boilers, located at two facilities within the jurisdiction of the South Coast AQMD. Boiler 1 has a rated heat input capacity of 115 MMBtu/hr and has a permitted NOx limit of 21 ppmv at 3 percent oxygen on a dry basis. Boiler 1 is equipped with flue gas recirculation and a low NOx burner. Boiler 1 source tested at 17 ppmv NOx at 3 percent oxygen on a dry basis in September 2018. Boiler 2 and Boiler 3 each have a rated heat input capacity of 335 MMBtu/hr and have a permitted NOx limit of 24 ppmv at 3 percent oxygen on a dry basis. Boilers 2 and 3 are equipped with flue gas recirculation. Boiler 2 source tested at 18.8 ppmv NOx at 3 percent oxygen on a dry basis in June 2018 and Boiler 3 source tested at 20.7 ppmv NOx at 3 percent oxygen on a dry basis in June 2019.

Figure 2-2 Landfill Gas Fired Boiler Source Test Results



Turbines <0.3 MW

There are four permitted landfill gas turbines rated 0.2 MW located at one facility in the South Coast AQMD. All four turbines have a permitted NOx concentration limit of 9 ppmv at 15 percent oxygen on a dry basis. April 2020 source test results are between 3.29 ppmv and 3.39 ppmv NOx at 15 percent oxygen on a dry basis.

Turbines ≥ 0.3 MW

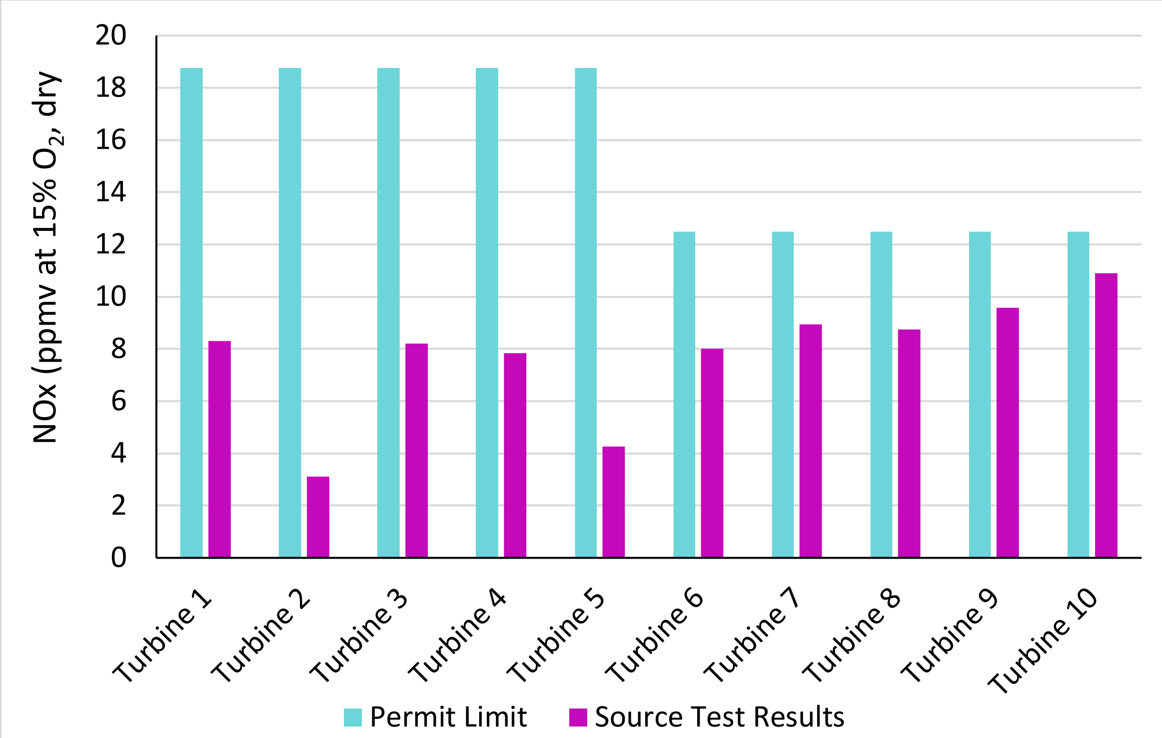
There are 14 turbines rated greater than or equal to 0.3 MW permitted to fire on landfill gas at four facilities. Ten are simple cycle turbines which utilize ultra-lean pre-mix control technology as NOx controls. Five simple cycle turbines have permitted NOx limits of 18.75 ppmv for loads greater than 3000 kW and 25 ppmv for loads less than or equal to 3000 kW. The other five simple cycle turbines have a permitted NOx limit of 12.5 ppmv. There are four combined cycle turbines which utilize selective catalytic reduction (SCR) to control NOx emissions. The combined cycle turbines have a permitted NOx limit of 25 ppmv. All NOx limits are at 15 percent oxygen on a dry basis.

TABLE 2-1
CURRENT PERMIT LIMITS FOR LANDFILL GAS TURBINES

Facility	Number of Turbines	Turbine Size (MW)	Cycle Type	Emission Controls	NOx Permit Limit (ppmv at 15% O2)
1	3	4.6	Simple	Ultra-lean Premix	18.75 at loads >3000 kW; 25 at loads ≤ 3000 kW
2	2	4.6	Simple	Ultra-lean Premix	18.75 at loads >3000 kW; 25 at loads ≤ 3000 kW
3	5	4.9	Simple	Ultra-lean Premix	12.5
4	4	6.3	Combined	SCR	25

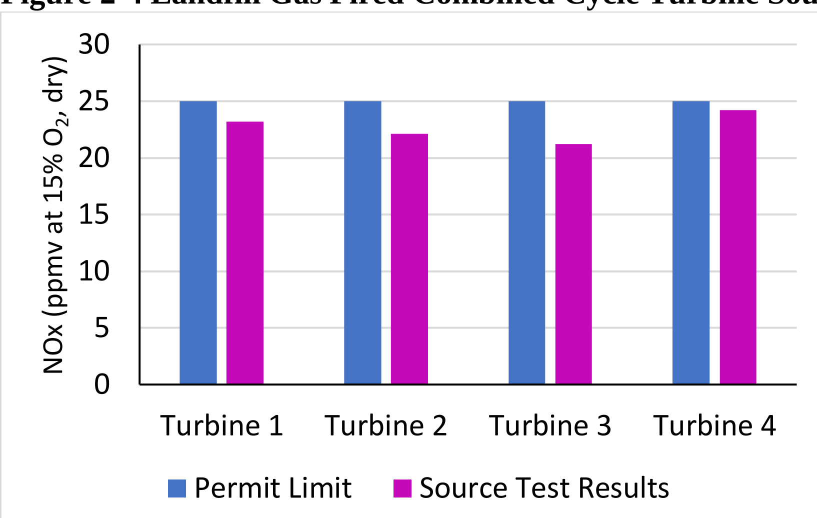
Staff analyzed recent source test results for the fourteen turbines; source tests were conducted between September 2015 and January 2020. Source test results for the simple cycle turbines showed NOx concentrations between 3.1 ppmv and 10.9 ppmv NOx at 15 percent oxygen on a dry basis (see Figure 2-3).

Figure 2-3 Landfill Gas Fired Simple Cycle Turbine Source Test Results



September 2019 source test results for combined cycle turbines showed NOx concentrations between 21.2 and 24.2 ppmv (see Figure 2-4).

Figure 2-4 Landfill Gas Fired Combined Cycle Turbine Source Test Results



Other Regulatory Requirements

Boilers and Process Heaters

Based on a review of requirements at other air districts, staff identified that San Joaquin Valley Air Pollution Control District (SJVAPCD) and Sacramento Metropolitan Air Quality Management District (SMAQMD) adopted rules that are more stringent than the South Coast AQMD for landfill gas fired boilers and process heaters.

SJVAPCD Rule 4320 applies to gaseous and liquid fuel fired boilers, steam generators, or process heaters with a total rated heat input greater than 5 MMBtu/hr. Rule 4320 limits NOx emissions to between 6 ppmv – 9 ppmv at 3 percent oxygen for boilers and process heaters greater than 5 MMBtu/hr to ≤ 20 MMBtu/hr. SJVAPCD further limits NOx emissions to 5 ppmv – 7 ppmv at 3 percent oxygen for boilers and process heaters greater than 20 MMBtu/hr. The NOx limits became effective between July 1, 2010 and January 1, 2014 and apply to gaseous or liquid fuels for boilers and process heaters, where "gaseous fuel" is defined as any fuel which is a gas at standard conditions. SJVAPCD Rule 1020 defines standard conditions as a gas temperature of 60 degrees Fahrenheit and a gas pressure of 14.7 pounds per square inch absolute. Rule 4320 does not specify a NOx limit for units specifically fueled by landfill gas. In addition, the NOx emission limits in Rule 4320 have not been demonstrated as achievable for landfill gas fired boilers and process heaters, as there are no existing landfill gas fired boilers or process heaters in SJVAPCD.

SMAQMD Rule 411 applies to boilers, steam generators, and process heaters fired on gaseous or nongaseous fuels with a rated heat input capacity of 1 MMBtu/hr and greater. Rule 411 restricts NOx emissions to 15 ppmv at 3 percent oxygen for boilers and process heaters greater than or equal to 5 MMBtu/hr fired using landfill gas or a combination of landfill gas and natural gas. The NOx limit became effective between October 27, 2007 and October 27, 2009, depending on the number of units at a facility. Based on a 2009 source test, a landfill gas boiler in SMAQMD had a NOx concentration of 6.9 ppmv NOx, which is well below the 15 ppmv limit. In 2010, the boiler switched to firing exclusively natural gas due to low landfill gas volume. Currently, there are no permitted landfill gas boilers in SMAQMD.

Turbines <0.3 MW

Staff did not identify any air districts that adopted rules regulating NOx emissions for turbines rated less than 0.3 MW. The State of California has issued certification requirements for turbines, including turbines rated less than 0.3 MW, that are exempt from any District requirements. Such turbines fueled by waste gas must comply with the California Air Resources Board Distributed Generation Certification Regulation emission standards of 0.07 lbs/MW-hr NOx on or after January 1, 2013. Currently, there are no landfill gas fueled turbines certified to the 2013 waste gas emission standard. Existing unpermitted units that were certified to the 2008 waste gas emission standard of 0.5 lbs/MW-hr NOx can no longer be sold in California unless permitted by a local air district.

Turbines ≥ 0.3 MW

Based on reviews of requirements at other air districts, staff identified that SJVAPCD, SMAQMD, and Bay Area Air Quality Management District (BAAQMD) adopted rules that are more stringent than South Coast AQMD permit limits for landfill gas fired turbines rated 0.3 MW or greater.

SJVAPCD Rule 4703 applies to stationary gas turbines, which are subject to permit requirements, and with ratings equal to or greater than 0.3 MW or a maximum heat input rating of more than 3 MMBtu/hr. Table 2-2 contains SJVAPCD Rule 4703 NOx limits which are more stringent than South Coast AQMD permits for landfill gas fired turbines. However, it should be noted that Rule 4703 does not specify a NOx limit for units specifically fueled by landfill gas. The NOx emission limits of SJVAPCD have not been demonstrated as achievable for landfill gas fueled turbines, as there are no existing landfill gas turbines in SJVAPCD.

TABLE 2-2
SJVAPCD NOx EMISSION LIMITS FOR GASEOUS FUEL TURBINES

Equipment Category	NOx Emission Limit (ppmv at 15% O_2)	Compliance Date
< 3 MW	9	No later than January 1, 2012
3 MW to 10 MW and permit condition for < 877 hrs/yr operation	9	
3 MW to 10 MW and permit condition for ≥ 877 hrs/yr operation	5	
> 10 MW, simple cycle, and permit condition for no greater than 200 hrs/yr operation	25	
> 10 MW, simple cycle, and permit condition for > 200 hrs/yr operation but no greater than 877 hrs/yr operation	5	
> 10 MW, simple cycle, and permit condition for > 877 hrs/yr operation, standard compliance option	5	April 30, 2005
> 10 MW, simple cycle, and permit condition for > 877 hrs/yr operation, enhanced compliance option	3	
> 10 MW, combined cycle, standard compliance option	5	April 30, 2004
> 10 MW, combined cycle, enhanced compliance option	3	

SMAQMD Rule 413 applies to stationary gas turbines with ratings greater than or equal to 0.3 MW or 3 MMBtu/hr. Table 2-3 contains SMAQMD Rule 413 NOx limits which are more stringent than South Coast AQMD permits for landfill gas fired turbines. However, all existing South Coast AQMD permits are as stringent or more stringent than SMAQMD Rule 413 when taking equipment categories into consideration. Rule 413 does not specify a NOx limit for units specifically fueled by landfill gas. There are no existing landfill gas fueled turbines in SMAQMD, so the NOx emission limits have not been demonstrated as achievable for landfill gas fueled turbines.

TABLE 2-3
SMAQMD NOx EMISSION LIMITS FOR GASEOUS FUEL TURBINES

Equipment Category	NOx Emission Limit (ppmv at 15% O_2)	Compliance Date
≥ 0.3 MW to < 2.9 MW	42	May 31, 1997
≥ 2.9 MW and < 877 hrs/yr operation	42	
≥ 2.9 MW to < 10 MW and ≥ 877 hrs/yr operation	25	
≥ 10 MW (no SCR) and ≥ 877 hrs/yr operation	15	
≥ 10 MW (with SCR) and ≥ 877 hrs/yr operation	9	

BAAQMD Regulation 9 – Rule 9 applies to stationary gas turbines with a heat input greater than or equal to 5 MMBtu/hr. Table 2-4 contains BAAQMD Regulation 9 – Rule 9 NOx limits which are more stringent than South Coast AQMD permits for landfill gas fired turbines. However, all existing South Coast AQMD permits are more stringent than BAAQMD Regulation 9 – Rule 9 when taking equipment categories into consideration.

TABLE 2-4
BAAQMD NOx EMISSION LIMITS FOR REFINERY FUEL GAS, WASTE GAS, OR LPG TURBINES

Equipment Category	NOx Emission Limit (ppmv at 15% O_2)	Compliance Date
5 – 50 MMBtu/hr	50	January 1, 2010
> 50 – 150 MMBtu/hr	50	
> 150 – 250 MMBtu/hr	15	
> 250 – 500 MMBtu/hr	9	
> 500 MMBtu/hr	9	

Assessment of Pollution Control Technologies

Staff assessed NOx control technologies for landfill gas fired boilers and turbines. NOx control technologies include low NOx and ultra-low NOx burners, flue gas recirculation, selective catalytic reduction (SCR), lean premixed combustion, and water and steam injection. MSW landfills and LFGTE facilities utilize gas treatment technology to prevent damage to NOx control technologies.

<u>Gas Treatment for Boilers, Process Heaters, and Turbines</u>
Gas treatment technology is commonly used to remove siloxanes, moisture, hydrogen sulfide, and other undesirable contaminants from raw landfill gas prior to combustion. The removal of siloxanes from raw landfill gas is vital for combustion equipment and control technology to work efficiently and prevent damage. There are three primary types of gas treatment systems for siloxane

removal: consumable media, regenerative media, and chiller/adsorption. A gas treatment system may contain one or more siloxane removal system types.

The effectiveness of siloxane removal depends on the media characteristics and the types of contaminants in the gas stream. Three common types of media used at landfills and LFGTE facilities are activated carbon, molecular sieve, and silica gel. Each type of media has its advantages. Activated carbon is a versatile adsorbent that is highly porous and is suitable to absorb 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 systems commonly use activated carbon as media. The activated carbon is typically stored in a series of parallel canisters which are changed out after the carbon is saturated. Activated carbon media is quickly saturated due to the adsorption of many contaminants. The removal and disposal of media can have a significant cost depending on the frequency the media is changed. However, initial installment and maintenance costs are typically less than regenerative media and chiller/adsorption systems due to the lack of complex machinery.

Regenerative media includes molecular sieve, silica gel, clay, and zeolite. These systems consist of at least two media canisters in parallel— one canister remains online and treats the gas while one canister remains offline to regenerate media with hot purged air. Regenerative media require smaller canisters and less media in comparison to consumable media systems. Regenerative media can be enhanced by applying polymetric resins. Polymetric resins can increase service life, increase adsorbent capacity, and removes contaminants more quickly and at a lower temperature during regeneration.

Chiller/adsorption gas treatment systems remove contaminants by reducing the temperature of the gas to below dew point to condense out moisture and siloxanes. These systems have been used in combination with consumable media systems and regenerative media systems at landfills.

Boilers and Process Heaters

Low NOx burners, ultra-low NOx burners, flue gas recirculation, and selective catalytic reduction (SCR) are control technologies which reduce NOx emissions from boilers and process heaters.

- Low NOx and Ultra-Low NOx Burners

Low NOx burners and ultra-low NOx burners control the air-fuel mixture at the burner. Optimal air-fuel ratios reduce the peak flame temperature which reduces NOx. Low NOx burners can reduce NOx by 60% and result in NOx concentrations of approximately 15 ppmv at 3 percent oxygen on a dry basis. Ultra-low NOx burners can reduce NOx by 80% to NOx concentrations of approximately 9 ppmv at 3 percent oxygen on a dry basis. Burner retrofits to an existing boiler may require complex engineering and design. One landfill gas fired boiler in the South Coast AQMD utilizes a low NOx burner.

- Flue Gas Recirculation

Flue gas recirculation is a method of NOx control that returns hot combustion exhaust products out of the flue gas and recirculates them back through a boiler or burner. This process helps preheat the incoming combustion air and lowers the combustion zone temperature to reduce NOx formation. This technology can reduce NOx by 30–55%. Flue gas recirculation is currently used on all landfill gas fired boilers in South Coast AQMD.

- Selective Catalytic Reduction (SCR)

SCR is a post-combustion control technology for NOx reduction and is capable of reducing 80–95% of post-combustion NOx. This technology is capable of reducing NOx to approximately 5 ppmv at 3 percent oxygen on a dry basis for landfill gas fired boilers. SCR reduces NOx to nitrogen and water through a reaction with ammonia and oxygen. However, the catalyst used for the reaction is susceptible to fouling if the gas contains contaminants such as siloxanes or hydrogen sulfide. Landfill gas fired turbines utilizing SCR would require gas treatment to preserve the catalyst. SCR may be used in combination with combustion control technologies to achieve greater NOx reductions. Additionally, 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. SCR is also limited by its range of optimum operating temperatures. The technology typically requires exhaust temperatures to be between 400–800°F, so it is not suitable for combustion equipment with low exhaust temperatures.

<u>Turbines <0.3 MW</u>

Lean premixed combustion is a NOx control technology commonly used for turbines rated less than 0.3 MW. This control technology premixes gaseous fuel and compressed air which minimizes localized hot spots that produce elevated combustion temperatures. Lean premixed combustion can reduce NOx to approximately 9 ppmv at 15 percent oxygen. However, this control technology requires that the combustor is an intrinsic part of the turbine design and is not available as a retrofit technology. One turbine supplier guarantees a 9 ppmv NOx limit at 15 percent oxygen on a dry basis for turbines rated less than 0.3 MW that fire landfill gas. However, proper gas treatment and maintenance is imperative to meet the target emission levels. All landfill gas fired turbines rated less than 0.3 MW use lean premixed combustion technology in combination with a gas treatment system.

SCR is not a technologically feasible control for turbines rated less than 0.3 MW due to low exhaust temperature. SCR requires high exhaust temperatures between 400–800°F to activate catalysts.

<u>Turbines ≥ 0.3 MW</u>

Lean premixed combustion, water or steam injection, and SCR are NOx control technologies commonly used for turbines rated 0.3 MW or greater.

- Lean Premixed Combustion

As previously stated above for turbines < 0.3 MW, lean premixed combustion is a control technology that reduces NOx from turbines. Prior to combustion, gaseous fuel and compressed air are premixed which minimizes localized hot spots that produce elevated combustion temperatures.

Lean premixed combustion can reduce NOx to approximately 12.5 ppmv at 15 percent oxygen on a dry basis. However, this control technology requires that the combustor is an intrinsic part of the turbine design and is not available as a retrofit technology. All ten simple cycle landfill gas fired turbines rated 0.3 MW and greater use lean premixed combustion in combination with a gas treatment system.

- Water and Steam Injection

Water or steam injection reduces NOx by injecting water or steam into the flame zone to lower the combustion zone temperature. Water injection can reduce NOx by 80–90% and steam injection can reduce NOx by 70–80% to approximately 25 ppmv. However, water and steam injection require demineralized water which increases operational costs. Imprecise application can also lead to hotspots and cause NOx formation. Furthermore, water and steam injection increases fuel usage and carbon monoxide (CO) emissions.

- Selective Catalytic Reduction (SCR)

SCR is a post-combustion control technology for NOx reduction and is capable of reducing 80–95% of post-combustion NOx. This technology can reduce NOx concentrations to 2.5 ppmv at 15 percent oxygen on a dry basis for simple cycle turbines and 2 ppmv at 15 percent oxygen on a dry basis for combined cycle turbines. SCR reduces NOx to nitrogen and water through a reaction with ammonia and oxygen. However, the catalyst used for the reaction is susceptible to fouling if the gas contains contaminants such as siloxanes or hydrogen sulfide. Landfill gas fired turbines utilizing SCR require gas treatment to preserve the catalyst. SCR may be used in combination with combustion control technologies to achieve greater NOx reductions. However, 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. SCR is limited by its range of optimum operating temperatures. The technology typically requires exhaust temperatures to be between 400–800°F, so it is not suitable for combustion equipment with low exhaust temperatures. All four combined cycle landfill gas fired turbines rated 0.3 MW and greater use SCR in combination with a gas treatment system.

Initial BARCT Emission Limits and Other Considerations

Boilers and Process Heaters

Staff proposed a NOx emission limit of 5 ppmv at 3 percent oxygen on a dry basis. This initial BARCT limit was based on the technology assessment of SCR used with landfill gas fired boilers.

TABLE 2-5
INITIAL NOx EMISSION LIMITS FOR LANDFILL GAS BOILERS AND PROCESS HEATERS

Equipment Type	NOx Limit at Rule Adoption (ppmv)*
Boilers and Process Heaters	5

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

Turbines < 0.3 MW
Staff proposed a NOx limit of 9 ppmv at 15 percent oxygen on a dry basis based on the technology assessment of lean premixed combustion. Existing landfill gas fired turbines rated less than 0.3 MW are currently permitted at 9 ppmv and use lean premixed combustion. Source test results from existing turbines demonstrate that the 9 ppmv NOx limit has been achieved.

TABLE 2-6
INITIAL NOx EMISSION LIMITS FOR LANDFILL GAS TURBINES < 0.3 MW

Equipment Type	NOx Limit at Rule Adoption (ppmv)*
Turbines < 0.3 MW	9

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

Turbines ≥ 0.3 MW
Staff proposed a NOx limit of 2.5 ppmv at 15 percent oxygen on a dry basis for simple cycle turbines and 2 ppmv at 15 percent oxygen on a dry basis for combined cycle turbines. These initial BARCT limits were based on the technology assessment of SCR used with landfill gas fired turbines.

TABLE 2-7
INITIAL NOx EMISSION LIMITS FOR LANDFILL GAS TURBINES ≥ 0.3 MW

Equipment Type	NOx Limit at Rule Adoption (ppmv)*
Simple Cycle Turbines ≥ 0.3 MW	2.5
Combined Cycle Turbines ≥ 0.3 MW	2

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

Cost- Effectiveness and BARCT Emission Limits

A complete discussion of cost-effectiveness is provided in Chapter 4 of this report. The findings are summarized here as part of the BARCT assessment process.

Boilers and Process Heaters
Staff conducted a cost-effectiveness analysis to retrofit landfill gas fired boilers with SCR. The average cost effectiveness to meet a 5 ppmv NOx limit at 3 percent oxygen on a dry basis was determined to be greater than $50,000 per ton of NOx reduced.

Staff then proceeded to conduct a cost-effectiveness analysis to retrofit landfill gas fired boilers with ultra-low NOx burners. The average cost effectiveness to meet a 9 ppmv NOx limit at 3 percent oxygen on a dry basis was determined to be less than $50,000 per ton of NOx reduced.

Staff is proposing a NOx emission limit of 25 ppmv at 3 percent oxygen on a dry basis at rule adoption. This initially proposed NOx emission limit is consistent with Rules 1146 and 1146.1. Based on the cost-effectiveness analysis, staff is proposing a lower NOx limit of 9 ppmv at 3 percent oxygen on a dry basis on or before January 1, 2031. The compliance date reflects consideration of the end date for a power purchase agreement of an affected facility.

TABLE 2-8
PROPOSED BARCT NOx EMISSION LIMITS FOR LANDFILL GAS BOILERS AND PROCESS HEATERS

Equipment Type	Limit at Rule Adoption (ppmv)*	Limit on January 1, 2031 (ppmv)*
Boilers and Process Heaters	25	9

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

<u>Turbines < 0.3 MW</u>
All of the existing landfill gas fired turbines rated less than 0.3 MW are permitted at the initial BARCT emission limit of 9 ppmv NOx. There are no additional costs to meet the initial BARCT limit.

Staff is therefore proposing a NOx emission limit of 9 ppmv at 15 percent oxygen on a dry basis at rule adoption. This NOx limit is consistent with current landfill gas permits for turbines rated less than 0.3 MW and reflects the NOx concentration achievable with existing control technologies.

TABLE 2-9
PROPOSED BARCT NOx EMISSION LIMIT FOR LANDFILL GAS TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption (ppmv)*
Turbines < 0.3 MW	9

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

<u>Turbines ≥ 0.3 MW</u>
Staff conducted a cost-effectiveness analysis to retrofit simple cycle landfill gas fired turbines with SCR. The average cost effectiveness to meet a 2.5 ppmv NOx limit at 15 percent oxygen on a dry basis was determined to be greater than $50,000 per ton of NOx reduced.

Staff then conducted a cost-effectiveness analysis to meet a 9 ppmv NOx limit, consistent with SMAQMD Rule 413 and BAAQMD Regulation 9 – Rule 9. Based on the BARCT technology assessment, SCR would be required to meet a 9 ppmv NOx limit. The emission reductions associated with a 9 ppmv NOx limit is less than the initial BARCT emission limit of 2.5 ppmv, while the estimated cost for SCR is the same. The average cost-effectiveness to meet a 9 ppmv limit at 15 percent oxygen on a dry basis was determined to be greater than $50,000 per ton of NOx reduced. See Chapter 4 for details on costs of SCR for turbines.

The four existing combined cycle turbines currently utilize SCR as a control technology. Staff conducted a cost-effectiveness analysis to install a gas treatment system to meet a 12.5 ppmv NOx limit at 15 percent oxygen on a dry basis. The average cost effectiveness to meet a 12.5 ppmv NOx was determined to be greater than $50,000 per ton of NOx reduced.

Staff is proposing a NOx emission limit of 25 ppmv at 15 percent oxygen for turbines with post-combustion control upon rule adoption which would be consistent with existing permit limits for landfill gas fired turbines with post-combustion control (i.e. SCR). Staff is proposing a NOx emission limit of 12.5 ppmv at 15 percent oxygen for turbines without post-combustion control upon rule adoption. Source test results from existing turbines demonstrate that the 12.5 ppmv NOx limit has been achieved. Staff is proposing a NOx emission limit of 12.5 ppmv for turbines rated equal to or greater than 0.3 MW with post-combustion control upon turbine replacement.

TABLE 2-10
PROPOSED BARCT EMISSION LIMTS FOR LANDFILL GAS TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption (ppmv)*	Limit Upon Turbine Replacement (ppmv)*
Turbines ≥ 0.3 MW with post-combustion control	25	12.5
Turbines ≥ 0.3 MW without post-combustion control	12.5	12.5

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

SUMMARY OF BARCT EMISSION LIMITS

Table 2-11 contains a summary of proposed BARCT emission limits for landfill gas fired boilers, process heaters, and turbines effective upon rule adoption, a fixed date, and upon replacement.

TABLE 2-11
LANDFILL GAS EMISSION LIMITS AND COMPLIANCE SCHEDULE

Equipment Type	Limit at Rule Adoption (ppmv)	Limit on January 1, 2031 (ppmv)	Limit Upon Turbine Replacement (ppmv)
Boilers and Process Heaters[1]	25	9	NA
Turbines[2] < 0.3 MW	9	9	9
Turbines[2] ≥ 0.3 MW with post-combustion control	25	25	12.5
Turbines[2] ≥ 0.3 MW without post-combustion control	12.5	12.5	12.5

[1] *All emission limits are in parts per million by volume (ppmv) referenced at 3 percent oxygen on a dry basis.*
[2] *All emission limits are in parts per million by volume (ppmv) referenced at 15 percent oxygen on a dry basis.*

CHAPTER 3: PROPOSED RULE 1150.3

INTRODUCTION

The following information describes the structure of PR 1150.3 and explains the provisions incorporated from other source-specific rules. New provisions and any modifications to existing provisions that have been incorporated are also explained.

PROPOSED RULE STRUCTURE

PR 1150.3 will contain the following subdivisions:

- *a) Purpose*
- *b) Applicability*
- *c) Definitions*
- *d) Emission Limits*
- *e) Source Testing*
- *f) CEMS*
- *g) Diagnostic Emission Checks for Boilers and Process Heaters*
- *h) Recordkeeping*
- *i) Other Requirements*
- *j) Schedule for Permit Revisions*
- *k) Exemptions*

PROPOSED RULE 1150.3

Subdivision (a) – Purpose

The purpose of this rule is to limit NOx and CO emissions from boilers, process heaters, and turbines located at MSW landfills and LFGTE facilities.

Subdivision (b) – Applicability

PR 1150.3 applies to boilers and process heaters with a rated heat input capacity greater than 2 MMBtu/hr and turbines rated less than 0.3 MW, located at a MSW landfill or LFGTE facility, which are permitted to fire landfill gas, including dual fuel units that are permitted to fire landfill gas and another fuel. PR 1150.3 also applies to turbines rated greater than or equal to 0.3 MW located at an MSW landfill or LFGTE facility, regardless of the fuels the unit is permitted to fire. PR 1150.3 includes other gaseous or liquid fuel turbines since Rule 1134 requirements (which regulate turbines) specifically exclude turbines rated greater than or equal to 0.3 MW located at landfills or fueled by landfill gas.

Subdivision (c) – Definitions

PR 1150.3 incorporates definitions from other applicable source-specific rules to define fuels and other rule terms. New or modified definitions added to PR 1150.3 are:

- *BOILER means any combustion equipment fired with a liquid or gaseous fuel and used to produce steam or to heat water. Boiler does not include any open heated tank, adsorption* *chiller unit, or waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.*

This definition is from Rule 1146 and modified to include boilers used exclusively to produce electricity for sale.

- *COMBINED CYCLE TURBINE means a turbine that recovers heat from the gas turbine exhaust.*

  This definition is from Rule 1134 and modified for clarity by removing the term *COGENRATION GAS TURBINE*, which is not used in PR 1150.3.

- *CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) means the total combined equipment and systems, including the sampling interface, analyzers, and data acquisition and handling system, required to continuously determine air contaminants and diluent gas concentrations and/or mass emission rate of a source effluent (as applicable).*

  This definition is from Rule 218.1 and modified for clarity by incorporating the system description at the beginning of the definition.

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

  This definition was added to describe a type of unit that PR 1150.3 is applicable to. Dual fuel unit includes combustion equipment permitted to fire landfill gas and another fuel separately. Dual fuel unit also includes combustion equipment permitted to fire landfill gas and another fuel simultaneously, commonly referred to as co-fired.

- *LANDFILL GAS means any gas derived through a natural process from the decomposition of waste deposited in an MSW landfill.*

  This definition is from Rule 1118.1 and modified to include the term MSW landfill. If a gas meets the definition of both landfill gas and natural gas, it is considered to be natural gas, and the unit is required to meet the applicable natural gas emission limit.

- *LANDFILL GAS TO ENERGY FACILITY means a facility that receives and processes landfill gas to generate electricity for sale.*

  This definition was added to describe a type of facility that PR 1150.3 is applicable to.

- *MUNICIPAL SOLID WASTE or MSW LANDFILL means an entire disposal facility in a contiguous geographical space where solid waste is placed in or on land. An MSW landfill may be active, inactive, or closed.*
  A) Active MSW landfill means a Municipal Solid Waste landfill that has received solid waste on or after November 8, 1987.

B) *Inactive MSW landfill means a Municipal Solid Waste landfill that has not accepted solid waste after November 8, 1987 and subsequently no further solid waste disposal activity has been conducted within the disposal facility.*
C) *Closed MSW landfill means a Municipal Solid Waste landfill that has ceased accepting solid waste for disposal and the closure was conducted in accordance with all applicable federal, state and local statutes, regulations, and ordinances in effect at the time of closure.*

This definition is from Rule 1150.1 and modified to include the definitions of *ACTIVE MSW LANDFILL, INACTIVE MSW LANDFILL, AND CLOSED MSW LANDFILL.* This definition was modified to clarify that the closure of a *CLOSED MSW LANDFILL* was conducted in accordance with applicable rules and regulations.

- *OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide. NOx emissions means the sum of nitric oxides and nitrogen dioxides emitted, collectively expressed as nitrogen dioxide emissions.*

  This definition is from Rule 1118.1 and modified to include the definition of *NOx EMISSIONS* from Rule 1146.

- *POST-COMBUSTION CONTROL means air pollution control equipment which eliminates, reduces or controls the issuance of air contaminants after combustion.*

  This definition is modified from the Rule 102 definition of *CONTROL EQUIPMENT*.

- *PROCESS HEATER means any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. Process Heater does not include any kiln or oven used for drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.*

  This definition is from Rule 1146 and modified to simplify fuel types listed.

- *RATED HEAT INPUT CAPACITY means the heat input capacity as specified by the permit issued by the South Coast AQMD, or if not specified on the permit, as specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity. Heat input means the chemical heat released due to assumed complete combustion of fuel in a unit, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.*

  This definition is from Rule 1146 and modified to include the definition of *HEAT INPUT* from Rule 1146 and to refer to the South Coast AQMD instead of the Executive Officer.

- *RATING OF A TURBINE means the continuous MW (megawatt) rating or mechanical equivalent by a manufacturer for a turbine without including the increase in the turbine shaft output and/or the decrease in turbine fuel consumption by the addition of energy recovered from exhaust heat.*

  This definition is modified from the Rule 1134 definition to include the definition of *POWER AUGMENTATION* from Rule 1134.

- *SHUTDOWN means 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 1150.3.

- *SIMPLE CYCLE TURBINE means a turbine that does not recover heat from the combustion turbine exhaust gases to heat water or generate steam.*

  This definition is from Rule 1134 and was modified to apply to all turbines of this category, rather than exclusively stationary combustion turbines, subject to PR 1150.3.

- *SOLID WASTE means all decomposable and non-decomposable solid, semisolid and liquid wastes including garbage, trash, refuse, paper, rubbish, ashes, industrial waste, manure, vegetable or animal solid and semisolid waste.*

  This definition is from Rule 1150.1 and modified to clarify the types of waste disposed of at an MSW landfill.

- *STARTUP means the time period that begins when a unit combusts fuel after a period of zero fuel flow and which ends when the unit reaches steady operating conditions and as applicable, when the emission control system reaches full operation*.

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1150.3 and to clarify when startup ends.

- *TUNING means adjusting, optimizing, rebalancing, or other similar operations to a unit or an associated control device. Tuning does not include normal operations to meet load fluctuations.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1150.3.

- *TURBINE means 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 1150.3 applies to.

- *TURBINE REPLACEMENT means installing new equipment with the same function in place of currently installed equipment. Replacement does not include turbine overhauls that do not trigger New Source Performance Standards requirements, and overhauls in which the original turbine unit returns to operation at the facility within 90 days.*

  This definition is added to clarify a type of equipment modification made to a turbine. Turbine replacement includes replacing the combustor or burner of a turbine.

- *UNIT means a boiler, process heater, or turbine subject to this rule.*

  This definition is added for clarity when referencing equipment subject to the requirements of PR 1150.3.

Subdivision (d) – Emission Limits

Paragraph (d)(1) includes Table 1 (Table 3-1 and Table 3-2 in Draft Staff Report), which contains the emission requirements for NOx and CO for equipment subject to PR 1150.3. These emission requirements would not apply during periods of startup and shutdown, as further explained in paragraph (d)(5) – Startup and Shutdown.

TABLE 3-1
NOx AND CO CONCENTRATION LIMITS FOR BOILERS AND PROCESS HEATERS

BOILERS AND PROCESS HEATERS			
Equipment Category	**Compliance Schedule**	**NOx (ppmv)[1]**	**CO (ppmv)[1]**
Rated heat input capacity > 2 MMBtu/hr and firing exclusively landfill gas or dual fuel simultaneously firing landfill gas and natural gas	On and after [*Date of Adoption*]	25	400
	On and after January 1, 2031	9	
Rated heat input capacity > 2 MMBtu/hr and < 75 MMBtu/hr and firing exclusively natural gas	On and after [*Date of Adoption*]	9	
Rated heat input capacity ≥ 75 MMBtu/hr and firing exclusively natural gas	On and after [*Date of Adoption*]	5	

1 All parts per million by volume (ppmv) emission limits are referenced at 3% volume stack gas oxygen on a dry basis and averaged over 15 minutes.

Boilers and Process Heaters:

- Boilers and process heaters with a rated heat input greater than 2 MMBtu/hr firing exclusively landfill gas, or dual fuel boilers and process heaters which fire landfill gas and natural gas simultaneously, would meet the current Rule 1146 and Rule 1146.1 landfill gas limit of 25 ppmv NOx at 3 percent oxygen on a dry basis at the time of rule adoption.

- Boilers and process heaters with a rated heat input greater than 2 MMBtu/hr firing exclusively landfill gas, or dual fuel boilers and process heaters which fire landfill gas and natural gas simultaneously, would meet a 9 ppmv NOx limit at 3 percent oxygen on a dry basis by January 1, 2031.
- Boilers and process heaters with a rated heat input capacity > 2 MMBtu/hr and < 75 MMBtu/hr and firing exclusively natural gas will meet the current Rule 1146 (Group II and Group III units) and Rule 1146.1 limit of 9 ppmv NOx at 3 percent oxygen at municipal sanitation service facilities at the time of rule adoption. This equipment category applies to dual fuel boilers and process heaters firing exclusively natural gas. Boilers and process heaters that are not permitted to fire landfill gas are not subject to PR 1150.3, and will continue to be regulated under Rules 1146 and 1146.1.
- Boilers and process heaters with a rated heat input capacity ≥ 75MMBtu/hr firing exclusively natural gas will meet the current Rule 1146 limit of 5 ppmv NOx at 3 percent oxygen for Group I units at the time of rule adoption. This equipment category applies to dual fuel boilers and process heaters firing exclusively natural gas. Boilers and process heaters that are not permitted to fire landfill gas are not subject to PR 1150.3, and will continue to be regulated under Rules 1146 and 1146.1.
- All boilers and process heaters will continue to meet the current CO limit of 400 ppmv in Rules 1146 and 1146.1.

Dual fuel boilers and process heaters which fire landfill gas and natural gas simultaneously would be subject to the same NOx limit as exclusively landfill gas fired boilers and process heaters under PR 1150.3. Staff decided to exclude a weighted limit in PR 1150.3 for boilers and process heaters because there are currently no permitted dual fuel boilers or process heaters which fire landfill gas and natural gas simultaneously in the South Coast AQMD. Exclusion of a weighted limit in PR 1150.3 allows flexibility in the permitting process to determine the parameters of a more stringent NOx limit for any future dual fuel boilers and process heaters which simultaneously fire landfill gas and natural gas.

TABLE 3-2
NOx AND CO CONCENTRATION LIMITS FOR TURBINES

TURBINES			
Equipment Category	**Compliance Schedule**	**NOx (ppmv)[1]**	**CO (ppmv)[1]**
Rated output < 0.3 MW and firing exclusively landfill gas or dual fuel	On and after [*Date of Adoption*]	9	130
Rated output ≥ 0.3 MW with post-combustion control and firing ≥ 75% landfill gas[2]	On and after [*Date of Adoption*]	25	
Rated output ≥ 0.3 MW without post-combustion control and firing ≥ 75% landfill gas[2]	On and after [*Date of Adoption*]	12.5[3]	
Rated output ≥ 0.3 MW with post-combustion control and firing ≥ 75% landfill gas[2]	Upon turbine replacement	12.5[3]	
Rated output ≥ 0.3 MW and firing < 75% landfill gas[2]	On and after [*Date of Adoption*]	Limit in Paragraph (d)(2)	
Combined cycle with a rated output ≥ 0.3 MW and firing exclusively natural gas	On and after [*Date of Adoption*]	2	
Simple cycle with a rated output ≥ 0.3 MW and firing exclusively natural gas	On and after [*Date of Adoption*]	2.5	

1 All parts per million by volume (ppmv) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 1 hour.
2 Percent of landfill gas shall be based on the total heat input on a rolling 12-month basis.
3 Concentration limit applicable to turbines operating at a load of 55% rated output or greater, averaged over 1 hour.

Turbines < 0.3 MW:

Turbines less than 0.3 MW will be subject to the requirements of PR 1150.3 when firing landfill gas exclusively and dual fuel turbines that fire landfill gas and another fuel. Dual fuel includes turbines that are firing landfill gas and another fuel simultaneously and turbines firing landfill gas and another fuel separately. Turbines in this category would be subject to a 9 ppmv NOx limit and 130 ppmv CO limit at the time of rule adoption, both limits at 15 percent oxygen on a dry basis.

Turbines less than 0.3 MW that do not use landfill gas are not subject to PR 1150.3 as they will be regulated under Proposed Amended Rule 1147 for miscellaneous combustion equipment.

Turbines ≥ 0.3 MW:

- Turbines rated ≥ 0.3 MW with post-combustion control and firing ≥ 75% landfill gas are subject to their current permit limit of 25 ppmv NOx at 15 percent oxygen on a dry basis at the time of rule adoption
- Turbines rated ≥ 0.3 MW without post-combustion control and firing ≥ 75% landfill gas are subject to a 12.5 ppmv NOx limit at 15 percent oxygen on a dry basis at the time of rule adoption
- Turbines rated ≥ 0.3 MW with post-combustion control and firing ≥ 75% landfill gas are subject to a 12.5 ppmv NOx limit at 15 percent oxygen on a dry basis at the time of turbine replacement
- All turbines rated ≥ 0.3 MW are subject to a 130 ppmv CO limit at 15 percent oxygen on a dry basis at the time of rule adoption

The NOx and CO emission limits listed above apply to turbines that fire 75 percent or more landfill gas. The higher emission limits in PR 1150.3 for landfill gas fired turbines are capped at 75 percent or more landfill gas to reflect the current permit thresholds for the minimum use of landfill gas for the affected facility. The percentage of landfill gas is based on the total heat input on a rolling 12-month basis.

A dual fuel turbine that fires less than 75 percent landfill gas simultaneously with natural gas would be required to use a weighted emission limit determined by Equation 1, in paragraph (d)(2) explained below. The percentage of landfill gas is based on the total heat input on a rolling 12-month basis. The weighted emission limit only applies to turbines that fire landfill gas and natural gas simultaneously.

A turbine that fires exclusively natural gas would be required to meet the same natural gas NOx limits in Rule 1134. Rule 1134 requires natural gas simple cycle turbines to meet 2.5 ppm NOx at 15 percent oxygen on a dry basis and natural gas combined cycle turbines to meet 2 ppm NOx at 15 percent oxygen on a dry basis. There are currently no turbines permitted to fire only natural gas or dual fuel turbines that are permitted to fire landfill gas and natural gas separately at an MSW landfill or LFGTE facility. However, since Rule 1134 specifically excludes turbines operating at landfills, regardless of fuel, it is appropriate that PR 1150.3 include these requirements. A dual fuel turbine would be required to meet the natural gas limits in Table 1 (Table 3-2 in Draft Staff Report) when firing exclusively natural gas.

The CO emission limit for all turbines of 130 ppmv NOx at 15 percent oxygen on a dry basis is based on permit limits from the affected facilities. If a permit contains a more stringent CO limit than PR 1150.3, the owner or operator must comply with the more stringent limit.

Emission limits for Turbines that Fire Less than 75 percent Landfill Gas Simultaneously with Natural Gas – Paragraph (d)(2)

Turbines which fire landfill gas and more than 25 percent but less than 100 percent natural gas simultaneously are subject to the natural gas limit in Table 1 (Table 3-2 in Draft Staff Report) or the weighted emission limit calculated by Equation 1. Subparagraph (d)(2)(B) requires the landfill gas higher heating value used in the equation to be obtained using an approved procedure by the South Coast AQMD that includes submitting landfill gas samples for laboratory analyses and using portable monitoring devices, for example. A representative sample of the facility's landfill gas is allowed provided 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 landfill 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 landfill gas.

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

Where:

CL_A = compliance limit in Table 1 (Table 3-2 in Draft Staff Report) when firing 75% landfill gas or more

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

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

CL_B = compliance limit in Table 1 (Table 3-2 in Draft Staff Report) when firing exclusively natural gas

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

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

Emission Limits for Turbines ≥ 0.3 MW Operating at Loads less than 55 Percent Rated Output – Paragraph (d)(3)

The NOx limit of 12.5 ppmv in Table 1 (Table 3-2 in Draft Staff Report) does not apply to turbines rated greater than or equal to 0.3 MW while operating at loads less than 55 percent rated output. When operating at loads less than 55 percent rated output, turbines would be subject to a 25 ppmv NOx limit, but for a limited amount of run time. After operating at loads less than 55 percent rated output for 300 hours per calendar year, the 12.5 ppmv NOx limit would then become effective even if the facility continued to operate at loads less than 55 percent rated output for the duration of the calendar year. The NOx concentration limits in paragraph (d)(3) exclude periods of start-up and shutdown as specified in paragraph (d)(5).

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

PR 1150.3 provides averaging time requirements for boilers, process heaters, and turbines with CEMS. The proposed averaging times are as follows:

- Boilers and Process Heaters: Fixed interval of 1 hour

- Turbines: Fixed interval of 1 hour

<u>Startup and Shutdown – Paragraph (d)(5)</u>

Startup and shutdown requirements are provided in PR 1150.3 for boilers, process heaters, and turbines. The startup and shutdown requirements for boilers and process heaters are as follows:

- Boilers and process heaters without post-combustion control: No longer than is necessary for the proper operation of the boiler or process heater for startup and not longer than 6 hours for startup or shutdown
- Boilers and process heaters with post-combustion control: No longer than is necessary to reach minimum catalyst operating temperature for startup and not longer than 6 hours for startup or shutdown
- Boilers and process heaters ≥ 5 – 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per month (same as current Rule 429 requirements)
- Boilers and process heaters > 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per year (same as current Rule 429 requirements)

Maximum startup and shutdown requirements reflect current requirements in Rule 429 – Start-Up and Shutdown Exemption Provision for Oxides of Nitrogen. Boilers and process heaters currently subject to Rule 1146 are required to comply with Rule 429. Since landfill gas and dual fuel boilers would no longer be subject to Rule 1146, Rule 429 requirements have been included in PR 1150.3. Facilities are required to submit a startup and shutdown schedule by January 1 of each year to the South Coast AQMD to notify the South Coast AQMD of the dates, times, and duration of the scheduled startup and shutdown and of any other process variables requested by the South Coast AQMD. Scheduled startup and shutdown events include, but are not limited to, those planned for maintenance, service, tuning, or construction, and do not include startups or shutdowns triggered by demand response systems.

The startup and shutdown requirements for turbines are as follows:

- Turbines without post-combustion controls: No longer than is necessary for proper operation of the turbine and cannot exceed 30 minutes
- Turbines with post-combustion controls (e.g. SCR): No longer than is necessary for the post-combustion control equipment to reach minimum catalyst operating temperature for startup and not longer than 1 hour

<u>Prohibition of Liquid Fuel – Paragraph (d)(6)</u>

PR 1150.3 contains a prohibition on the use of any liquid fuel, such a diesel, for the operation of any turbine at an MSW landfill or LFGTE facility. This provision would not apply to emergency use turbines as described in the proposed exemptions under subdivision (k).

Subdivision (e) – Source Testing

For units and for pollutants not monitored by CEMS, PR 1150.3 provides a source testing schedule in Table 2 (Table 3-3 in Draft Staff Report). The source test is due no later than the last day of the calendar month in which the previous source test was conducted or required.

TABLE 3-3
NOx AND CO SOURCE TESTING SCHEDULE

Equipment Category	Frequency	Elapsed Time Prior to Conducting Source Test[1]
Boilers and process heaters with a rated heat input capacity > 2 MMBtu/hr and <10 MMBtu/hr	Every 5 years from the date the previous source test was performed or required, whichever is earlier	At least 250 operating hours or at least 30 calendar days
Boilers and process heaters with a rated heat input capacity ≥ 10 MMBtu/hr	Every 3 years from the date the previous source test was performed or required, whichever is earlier	At least 250 operating hours or at least 30 calendar days
Turbines with a rated output < 2.9 MW	Every 3 years from the date the previous source test was performed or required, whichever is earlier	At least 40 operating hours or at least 7 calendar days
Turbines with a rated output ≥ 2.9 MW	Every year from the date the previous source test was performed or required, whichever is earlier	At least 40 operating hours or at least 7 calendar days

1 Elapsed time subsequent to any tuning or servicing, unless tuning or servicing is due to an unscheduled repair.

The boiler and process heater requirements are the same as those contained in Rules 1146 and 1146.1. The source testing schedule for turbines is based on Rule 1134 requirements. The equipment categories which designate the source test frequency reflects the CEMS criterion in Rule 1134. The source testing requirements would apply to all turbines, including turbines rated less than 0.3 MW.

Subparagraph (e)(1)(A) is a new provision which contains an allowance for an owner or an operator of a turbine less than 2.9 MW to conduct a source test every 8,760 operating hours, in lieu of the source test frequency in Table 2 (Table 3-3 in Draft Staff Report). A non-resettable hour meter or alternative device which continuously records unit operating hours as approved by the South Coast AQMD is required to be installed and maintained in proper operation to use the source test schedule in subparagraph (e)(1)(A).

Subparagraph (e)(1)(B) is a new provision which contains an allowance for an owner or operator to delay a source test if a unit is not in operation on the date the source test is due. The source test is required by the end of seven consecutive days or 15 cumulative days of resumed unit operation.

Other source testing requirements, which come from existing source testing requirements from other source-specific rules, are contained in PR 1150.3 and apply to all 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 Paragraph (e)(1), 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 1150.3.

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

PR 1150.3 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 alteration to the equipment results in a change to the permit, if any emission limits have changed since the previous source test, or at the request of the South Coast AQMD. 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)

Paragraph (e)(4) describes the information required for submitting a source test protocol.

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

Paragraph (e)(5) contains requirements for notification of a scheduled source test.

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

Paragraph (e)(6) contains requirements that source tests are to be conducted by a South Coast AQMD approved contractor under the Laboratory Approval Program according to specific test methods. A listing of source testing methods is contained in Table 3 (Table 3-4 in Draft Staff Report).

TABLE 3-4

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

Source Testing Infrastructure – Paragraph (e)(7)

Paragraph (e)(7) contains requirements for physical accommodations that allow for a source test to be conducted at a facility.

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

Paragraph (e)(8) contains requirements to conduct source tests for boilers, process heaters, and turbines in the as-found operating condition, and that no testing should be completed during periods of startup, shutdown, or under breakdown conditions. PR 1150.3 includes a minimum sampling time of 15 minutes.

Submittal of Completed Source Test - Paragraph (e)(9)

Paragraph (e)(9) requires an owner or operator to submit source test reports to the South Coast AQMD within 60 days of the completed source test.

Subdivision (f) – CEMS

Subdivision (f) contains the requirements for the installation, operation, and maintenance of CEMS equipment. CEMS requirements are 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 may 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 Proposed Rules 218.2/218.3, upon adoption. Table 4 (Table 3-5 in Draft Staff Report) in subdivision (f) contains the thresholds for boilers, process heaters, and turbines requiring CEMS, consistent with current requirements in Rules 1146 and 1134, respectively.

TABLE 3-5

UNITS REQUIRING CEMS

Equipment Type	**Threshold**	**Pollutant**
Boilers and process heaters	Rated heat input capacity ≥ 40 MMBtu/hr and Annual heat input > 200 x 10^9 Btu per calendar year	NOx
Turbines	Rated output ≥ 2.9 MW	

Turbine Parameter Monitoring - Paragraph (f)(1)

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.

Subdivision (g) – Diagnostic Emission Checks for Boilers and Process Heaters

Subdivision (g) contains requirements that are consistent with current requirements in Rules 1146 and 1146.1. 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 Rules

1146, 1146.1, and 1110.2. The minimum sampling time for diagnostic emission checks is 15 minutes.

Boilers and Process Heaters ≥ 5 MMBtu/hr – Paragraph (g)(1)
Paragraph (g)(1) provides a diagnostic emission check frequency for boilers and process heaters with a rated heat input capacity greater than or equal to 5 MMBtu/hr. If the diagnostic emission check frequency has been reduced to quarterly or every 2,000 unit operating hours, the facility may continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption, until a diagnostic emission check exceeds the applicable limit.

Boilers and Process Heaters > 2 MMBtu/hr and < 5 MMBtu/hr – Paragraph (g)(2)
Paragraph (g)(2) provides a diagnostic emission check frequency for boilers and process heaters with a rated heat input capacity greater than 2 MMBtu/hr and less than 5 MMBtu/hr. If the diagnostic emission check frequency has been reduced to semi-annually or every 4,000 unit operating hours, the facility may continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption, until a diagnostic emission check exceeds the applicable limit.

Diagnostic Emission Check After Emission Exceedance – Paragraph (g)(3)
Paragraph (g)(3) allows for the owner or operator to resolve problems in the event of an emissions exceedance. Any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance would be a violation.

Subdivision (h) – Recordkeeping

Subdivision (h) harmonizes the recordkeeping requirements for the various types of equipment that will be subject to PR 1150.3. PR 1150.3 would additionally require an owner or operator to retain maintenance, service, and tuning records. Subdivision (h) would require records to be retained by an owner or operator for 5 years. Although other source-specific rules contain shorter records retention timeframes, such as 2 years, accumulation of the records would begin upon the date of adoption.

Recordkeeping for Boilers and Process Heaters - Paragraph (h)(1)
Subparagraphs (h)(1)(A) and (h)(1)(B) provide recordkeeping requirements based on Rule 429 – Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen that boilers and process heaters subject to Rule 1146 are currently subject to.

Recordkeeping for Turbines - Paragraph (h)(2)
Paragraph (h)(2) provides recordkeeping requirements for operators of turbines. Records of the total hours of operation, type of fuel used, fuel consumption and startup and shutdown times are required. The operating log is required to specify the hours of operation at loads less than 55 percent rated output to demonstrate compliance with the requirements of paragraph (d)(3). In addition, subparagraph (h)(2)(B) requires recordkeeping of emission control system operation and maintenance to verify continuous operation and compliance of an emission control device.

Recordkeeping for Units Required to Conduct Source Test - Paragraph (h)(3)
Paragraph (h)(3) requires records of the hours of operation of a unit since any tuning or servicing prior to conducting a source test.

Recordkeeping for Units Required to Conduct Diagnostic Emission Checks - Paragraph (h)(4)
Paragraph (h)(4) requires records of the hours of operation between diagnostic emission checks. The records must contain the date(s) of all: diagnostic emission checks, adjustments to oxygen set points, and exceedances of the applicable emission limit in Table 1 (Table 3-1 in Draft Staff Report).

Subdivision (i) – Other Requirements

Non-Resettable Hour Meter - Paragraph (i)(1)
Paragraph (i)(1) requires that an owner or operator of a boiler, process heater, or turbine rated greater than or equal to 0.3 MW to install and maintain in proper operation a non-resettable hour meter or alternative device which continuously records unit operating hours as approved by the South Coast AQMD. A CEMS which continuously records unit operating hours would meet the requirements of paragraph (i)(1), provided that the hours or operation can be verified by South Coast AQMD staff.

Subdivision (j) – Schedule for Permit Revisions

Subdivision (j) provides deadlines for permit applications to be submitted for revising equipment permits to reflect PR 1150.3. Facilities would only submit applications for equipment with permits that reference other source specific-rules no longer applicable once PR 1150.3 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 1150.3. Non-Title V facilities would submit applications on or before July 1, 2024 for each piece of equipment subject to PR 1150.3.

Subdivision (k) – Exemptions

Special Use Turbines - Paragraph (k)(1)
Paragraph (k)(1) provides exemption to turbines that are used only for firefighting or flood control. In addition, an exemption from PR 1150.3 requirements is provided for emergency standby turbines, which are defined here as well as in Rule 1134. An owner or operator must maintain an hour meter and an operating log to verify that each emergency standby turbine does not exceed a usage limit of 200 hours per year.

Non-Landfill Gas Turbines - Paragraph (k)(2)
Paragraph (k)(2) provides an exemption for turbines permitted to fire only non-landfill gas fuels. This exemption only applies to turbines that are not located at an MSW landfill.

MSW landfill means an entire disposal facility in a contiguous geographical space where solid waste is placed in or on land (see complete definition on page 3-2 and 3-3). A landfill gas to energy facility located on landfill property can meet the definition of MSW landfill. However, it is possible for landfill gas to energy facilities to not be located at an MSW landfill, if landfill gas is delivered via underground pipes, for example. In this case, a turbine not permitted to fire landfill gas would be exempt from PR 1150.3.

Paragraph (k)(2) is included in PR 1150.3 for non-duplication purposes. Rule 1134 applicability excludes turbines located at landfills or turbines fueled by landfill gas. Therefore, turbines that are not located at landfills, such as turbines located at landfill gas to energy facilities that do not meet the definition of landfill, are subject to Rule 1134 if the turbines are not firing landfill gas.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

Impact assessments were conducted during the PR 1150.3 rule development to assess environmental and socioeconomic implications of PR 1150.3. PR 1150.3 impact assessments include emission reductions calculations, cost-effectiveness analysis, incremental cost-effectiveness analysis, a socioeconomic assessment, and California Environmental Quality Act (CEQA) analysis. Staff prepared draft findings and comparative analyses pursuant to California Health and Safety Code Section (H&SC) 40727 and H&SC 40727.2, respectively.

EMISSION REDUCTIONS

PR 1150.3 will result in emission reductions for boilers and for turbines rated ≥ 0.3 MW without post-combustion control. Turbines rated ≥ 0.3 MW with post-combustion control will be required to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis at the time of replacement. Turbines rated < 0.3 MW will remain at the current permit limit of 9 ppmv NOx at 15 percent oxygen on a dry basis. Baseline emissions were determined using 2017 Annual Emissions Reports (AER).

Boilers

The total baseline emissions for one facility impacted by the proposed emission limit are approximately 22,211 pounds per year or 0.03 tons per day. The boiler has a NOx permit limit of 21 ppmv at 3 percent oxygen on a dry basis. The proposed emission limit of 9 ppmv at 3 percent oxygen on a dry basis would reduce NOx by approximately 0.02 ton per day for this boiler.

The baseline emissions for the other facility operating two boilers are approximately 104,031 pounds per year or 0.14 tons per day. These boilers have a NOx permit limit of 24 ppmv at 3 percent oxygen on a dry basis. The proposed emission limit of 9 ppmv at 3 percent oxygen on a dry basis would reduce NOx by approximately 0.09 ton per day for these boilers.

The total emission reductions for boilers is approximately 0.11 ton per day at a proposed emission limit of 9 ppmv at 3 percent oxygen on a dry basis. The proposed limit would become effective on January 1, 2031.

Turbines ≥ 0.3 MW Without Post-Combustion Control

The total baseline emissions for one facility operating two turbines impacted by the proposed emission limit are approximately 54,320 pounds per year or 0.07 tons per day. These turbines have a NOx permit limit of 18.75 ppmv at 15 percent oxygen on a dry basis at turbine loads >3000 kW. The baseline emissions for the other facility operating three turbines are approximately 37,718 pounds per year or 0.05 tons per day. These turbines have a NOx permit limit of 18.75 ppmv at 15 percent oxygen on a dry basis at turbine loads >3000 kW. The proposed emission limit of 12.5 ppmv at 15 percent oxygen on a dry basis would become effective upon rule adoption and reduce NOx by approximately 0.04 ton per day.

Both facilities have NOx permit limits of 25 ppmv at 15 percent oxygen on a dry basis when operating at loads ≤ 3000 kW. It is estimated that there will be no emission reductions when these turbines are operating at loads ≤ 3000 kW because PR 1150.3 contains a NOx limit of 25 ppmv at 15 percent oxygen on a dry basis for these turbines while operating at loads of less than 55% rated output.

Total NOx emission reductions from the proposed rule is approximately 0.15 ton 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 include purchasing, installation, operation, and maintenance of the control technology. Emissions reductions were based on the 2017 AER and the most recent source test data. 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, unless otherwise noted.

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

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

Staff obtained costs for control equipment from a variety of sources that included facilities 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. Existing O&M costs are not included in the cost-effectiveness calculation.

Boilers

A cost-effectiveness analysis was conducted for landfill gas fired boilers to meet a NOx concentration limit of 9 ppmv at 3 percent oxygen on a dry basis. Staff referred to the staff report for the December 2018 amendments to the Rule 1146 series for the costs of ultra-low NOx burners that meet a 9 ppmv NOx limit. Equipment costs ranged from $676,600-$1,952,600 depending on the size and the installation costs ranged from $221,300-$595,300 depending on size. Staff assumed a 15 year equipment life. The average cost-effectiveness to replace existing burners with a burner that can meet a NOx limit of 9 ppmv at 3 percent oxygen on a dry basis is $27,000 per ton of NOx.

The landfill gas that fuels existing boilers at MSW landfills and LFGTE facilities is declining. As a result, existing landfill gas fired boilers are expected to shut down by January 1, 2031. Staff proposed the 9 ppmv NOx limit to become effective January 1, 2031, to eliminate stranded asset costs. Table 4-1 summarizes the cost-effectiveness to require existing boilers to meet 9 ppmv NOx at 3 percent oxygen on a dry basis.

TABLE 4-1
COST-EFFECTIVENESS FOR PROPOSED BOILER EMISSION LIMITS

Cost-Effectiveness to Meet 9 ppmv NOx at 3 percent oxygen on a dry basis	
Emission Reductions Over 15 Years[1]	Cost-Effectiveness
63 tons (Facility 1)	$14,100 per ton of NOx reduced
348 tons (Facility 2)	$29,300 per ton of NOx reduced

[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.

Turbines ≥ 0.3 MW

A cost-effectiveness analysis was conducted for landfill gas fired turbines to meet a NOx concentration limit of 12.5 ppmv at 15 percent oxygen on a dry basis. Existing turbines with post-combustion control cannot meet a 12.5 ppmv NOx limit without enhanced gas cleanup. The estimated capital costs and O&M costs to install a gas cleanup system were obtained from the South Coast AQMD Biogas Toolkit Cost Estimator. The capital cost was estimated to be approximately $36,164,300 and the O&M cost was estimated to be approximately $9,237,300. The cost effectiveness for a gas cleanup system to meet a NOx limit of 12.5 ppmv at 15 percent oxygen on a dry basis is more than $50,000 per ton of NOx. PR 1150.3 would require turbines with post-combustion control to meet 12.5 ppmv NOx upon turbine replacement. Table 4-2 summarizes the cost-effectiveness to require existing turbines with post-combustion control to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis.

TABLE 4-2
COST-EFFECTIVENESS FOR PROPOSED TURBINE EMISSION LIMITS

Cost-Effectiveness for Turbines with Post-Combustion Control to Meet 12.5 ppmv at 15 percent oxygen on a dry basis	
Emission Reductions Over 25 Years[1]	Cost-Effectiveness
1194 tons (Facility 3 – turbines with SCR)	$151,100 per ton of NOx reduced

[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.

Existing turbines without post-combustion control can already meet 12.5 ppmv at 15 percent oxygen on a dry basis, as shown by source test results. There is only a one time capital cost for permit revision fees, so a cost-effectiveness analysis was not conducted.

Summary of Cost-Effectiveness Analysis

The proposed NOx BARCT emission limit for boilers of 9 ppmv NOx at 3 percent oxygen on a dry basis is proposed to be effective January 1, 2031. The proposed NOx BARCT emission limit for turbines rated greater than or equal to 0.3 MW without post-combustion control of 12.5 ppmv NOx at 15 percent oxygen on a dry basis is proposed to be effective on and after [Date of Adoption]. A summary of the cost-effectiveness analysis is in Table 4-3.

TABLE 4-3
COST-EFFECTIVENESS ANALYSIS

Category	Total Installed Cost (MM)	Annual Cost (MM)	Present Worth Value (MM)	NOx Reductions (tpd)	Cost-Effectiveness ($/ton)
Boilers and Process Heaters (To meet 9 ppmv)	$11.1	0	$11.1	0.11	$27,000

Permit Revisions

Permits are required to be revised to reflect PR 1150.3 and to remove the references to former source-specific rules that would no longer apply to these sources under Rule 1150.3. Facilities would incur a one-time cost at the time that permit revisions are required, according to the schedule in subdivision (j) of PR 1150.3. The total combined cost for all facility permit revisions is $33,469.53 Table 4-4 contains the breakdown costs for permit revisions, based on Rule 301 – Permitting and Associated Fees.

TABLE 4-4
PERMIT REVISION COSTS

Permit Revision Type	Cost (Non-Title V)	Cost (Title V)
Title V permit revision (per facility)	N/A	$1,518.26
Administrative Change (per equipment)	$962.75	$1,206.41

Source Testing

One PR 1150.3 facility operating four turbines rated less than 0.3 MW does not operate a CEMS or have permit conditions to source test for NOx and CO. Therefore, costs for source testing would increase under PR 1150.3 for the affected facility. The estimated source test cost was obtained from a local source testing company. The cost of a NOx and CO source test (three runs) is estimated to be approximately $6,000. PR 1150.3 requires a source test every 3 years for turbines rated less than 2.9 MW. The increased source test costs for the affected facility is estimated to be approximately $124, 976.

Total Cost-Effectiveness of PR 1150.3

The cost-effectiveness to implement PR 1150.3 is approximately $27, 337 per ton of NOx reduced. Costs include the cost for three boilers at two facilities to meet 9 ppmv NOx at 3 percent oxygen. The costs also include applicable permit revision fees for all units subject to PR 1150.3 and increased source test costs for four turbines at one facility

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 three boilers to meet 9 ppmv NOx at 3 percent oxygen on a dry basis at two facilities. The next progressively more stringent potential control option would be to require boilers and process heaters to meet 5 ppmv NOx at 3 percent oxygen on a dry basis. To meet 5 ppmv NOx, the facilities would be required to implement SCR with gas treatment on their existing boilers.

Incremental cost-effectiveness = ($416,090,656 – $11,096,155) / (955– 411) =
$744,475 per ton of NOx reduced

The proposed project would require five turbines to meet 12.5 ppmv NOx at 15 percent oxygen on a dry basis at two facilities. The next progressively more stringent potential control option would be to require turbines without post-combustion control to meet 2.5 ppmv NOx at 15 percent oxygen on a dry basis. To meet 2.5 ppmv NOx, the facilities would be required to implement SCR with gas treatment on their existing turbines.

Incremental cost-effectiveness = ($220,236,604 – $9,068) / (177 – 0) =
$1,244,223 per ton of NOx reduced

The incremental cost analyses presented above demonstrate that the alternative control options are not viable when compared to the control strategies of the proposed amendments.

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.

Proposed Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills (PR 1150.3) establishes Best Available Retrofit Control Technology (BARCT) requirements for boilers, process heaters, and turbines located at municipal solid waste (MSW) landfills and landfill gas to energy (LFGTE) facilities using exclusively landfill gas or a combination of landfill gas and natural gas. PR 1150.3 also contains monitoring, reporting, and recordkeeping provisions applicable to MSW landfills and LFGTE facilities.

Affected Facilities and Industries

PR 1150.3 establishes NOx and CO emission limits for boilers, process heaters, and turbines that are required to meet lower emission limits and that are fueled with landfill gas, natural gas, or a combination of landfill gas and natural gas. A total of 21 landfill gas fueled boilers and turbines at seven facilities will be affected by PR 1150.3 (three boilers, 14 turbines rated greater than or equal to 0.3 MW, and four turbines rated less than 0.3 MW).

The facilities affected by PR 1150.3 comprise six facilities in Los Angeles County and one facility in Orange County. Three facilities fall under the fossil fuel electric power generation industry North American Industrial Classification System (NAICS 221112), three facilities are in the solid waste landfill industry (NAICS 562212), and one facility is in materials recovery facilities industries (NAICS 562920).

Compliance Costs

Table 4-5 summarizes the compliance costs of PR 1150.3. All four of the existing landfill gas fired turbines rated less than 0.3 MW are permitted at the BARCT emission limit of 9 ppmv NOx, but incur source testing costs and one-time permit revision/administrative cost. Turbines rated greater than or equal to 0.3 MW without post-combustion control can meet the BARCT limit of 12.5 ppmv NOx with existing equipment, and only incur one-time permit revision/administrative cost. Emission limits based on enhanced gas treatment for turbines greater than or equal to 0.3 MW with post-combustion control were analyzed but were found to be not cost-effective (see Table 4-2 in the Preliminary Draft Staff Report for PR 1150.3).[1] Turbines rated greater than or equal to 0.3 MW with post-combustion control will be required to meet the BARCT limit 12.5 ppmv NOx upon turbine replacement. The proposed NOx limit for turbines with post-combustion control is

[1]http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/proposed-rule-1150.3/rule-1150-3-preliminary-draft-staff-report-final.pdf?sfvrsn=4 Accessed December 30, 2020.

consistent with existing permit limits and assumes a permit revision/administrative cost only. Title V permit revisions are $1,518.26 each, administrative change costs are $1,206.21 per piece of Title V equipment, and non-Title V equipment permit revisions are $962.75 each.

Ultra-low NOx burner (ULNB) installations are assumed for boilers to meet the BARCT emission limit of 9 ppmv NOx by January 1, 2031. There are no additional annual operating and maintenance costs associated with the new ULNBs because the burner retrofits have the same energy usage as the existing equipment. A one-time permit revision/administrative cost is assumed.

TABLE 4-5
PR 1150.3 COMPLIANCE COST BY CATEGORY (2021-2045)

Category	Total Compliance Cost (2021-2045)	# of Facilities	Pieces of Equipment	Source of Compliance Costs	Cost Effective? (<$50,000 per ton of NOx reduced)
Boilers & Process Heaters (to meet 9 ppmv @ 3% O2)	$11.1M	2	3	5 ULNB retrofits ($0.9-$5.1M each boiler) plus one-time permit revision/admin change (Title V $1,518.26, Title V administrative change $1,206.21 per piece of equipment)	Yes, ~$27,000 per ton of NOx reduced
Turbines ≥ 0.3 MW Without Post-Combustion Control (already meet 12.5 ppmv @15% O2)	$16,600	3	10	Permit Revision (Title V $1,518.26, Title V administrative change $1,206.21 per piece of equipment)	N/A*
Turbines ≥ 0.3 MW with Post-Combustion Control	$6,300	1	4*	Permit Revision (Title V $1,518.26, Title V administrative change $1,206.21 per piece of equipment)	No, BARCT limit is upon turbine replacement
Turbines < 0.3MW (already permitted at 9 ppmv @ 15% O2)	$129,000	1	4	Source tests for each turbine rated < 2.9 MW occur every 3 years @ $6,000 per turbine without CEMS plus one-time permit revision/admin change (non-Title V administrative change $962.75 per piece of equipment)	N/A*

* Cost-effectiveness not analyzed in categories where proposed limits not related to a new emission control installation

The total estimated annualized compliance costs of PR 1150.3 are estimated at $649,000 between 2021 and 2045, at four percent real interest rate.

Regional Macroeconomic Impacts

South Coast AQMD does not estimate regional macroeconomic impacts when the total annual compliance cost is less than one million current U.S. dollars as the Regional Economic Models Inc. (REMI)'s Policy Insight Plus Model is not able to reliably evaluate impacts that are so small relative to the baseline regional economy.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) Guidelines Sections 15002(k) and 15061, the proposed project is exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3). A Notice of Exemption will be prepared pursuant to CEQA Guidelines Section 15062. If the proposed project is approved, the Notice of Exemption will be electronically filed with the State Clearinghouse of the Governor's Office of Planning and Research to be posted on their CEQAnet Web Portal, which may be accessed via the following weblink: https://ceqanet.opr.ca.gov/search/recent. In addition, the Notice of Exemption will be electronically posted on the South Coast AQMD's webpage which can be accessed via the following weblink: http://www.aqmd.gov/nav/about/public-notices/ceqa-notices/notices-of-exemption/noe---year-2021. The electronic filing and posting of the Notice of Exemption is being implemented in accordance with Governor Newsom's Executive Orders N-54-20 and N-80-20 issued on April 22, 2020 and September 23, 2020, respectively, for the State of Emergency in California as a result of the threat of COVID-19.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make 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 1150.3 is needed to establish NOx and CO emission limits for landfill gas and/or natural gas fired boilers, process heaters, and turbines located at municipal solid waste landfills or landfill gas to energy facilities 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 1150.3 is written or displayed so that their meaning can be easily understood by the persons directly affected by them.

Consistency
PR 1150.3 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication
PR 1150.3 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

Health and Safety Code Section 40727.2 requires a comparative analysis of the proposed rule with any Federal or District rules and regulations applicable to the same source. A comparative analysis is presented below in Table 4-6 and Table 4-7.

TABLE 4-6
PR 1150.3 COMPARATIVE ANALYSIS – BOILERS AND PROCESS HEATERS

Rule Element	PR 1150.3	Rule 1146	Rule 1146.1	Rule 1135	Equivalent Federal Regulation
Applicability	Located at an MSW landfill or landfill gas to energy facility: Landfill gas and dual fuel boilers and process heaters with a rated heat input capacity > 2 MMBtu/hr	Boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations	Boilers, steam generators, and process heaters that are greater than 2 million Btu per hour and less than 5 million Btu per hour rated heat input capacity used in any industrial, institutional, or commercial operation.	Boilers, gas turbines, and diesel internal combustion engines on Santa Catalina Island that generate electric power located at investor-owned electric utilities, publicly owned electric utilities, or facilities with combined generation capacity of ≥ 50 MW excluding landfills, petroleum refineries, or publicly owned treatment works	None

Requirements	NOx emission limits @ 3% O_2: • > 2 MMBtu/hr and firing exclusively landfill gas or dual fuel simultaneously firing landfill gas and natural gas - 25 ppmv on and after date of adoption • > 2 MMBtu/hr and firing exclusively landfill gas or dual fuel simultaneously firing landfill gas and natural gas - 9 ppmv on and after January 1, 2031 • > 2 MMBtu/hr and < 75 MMBtu/hr and firing exclusively natural gas– 9 ppmv on and after date of adoption • ≥ 75 MMBtu/hr and firing exclusively natural gas– 5 ppmv on and after date of adoption CO Emission limit @ 3% O_2: 400 ppmv	NOx emission limits @ 3% O_2: • Any units fired on landfill gas and cofired units firing natural gas and 90% landfill gas or more, and cofired unit firing up to 25% natural gas with landfill gas if only alternative is shutting down and flaring – 25 ppmv by January 1, 2015 • Weighted limit for landfill gas unit burning more than 25% natural gas: $\frac{(CL_A \times Q_A) + (CL_B \times Q_B)}{(Q_A + QB)}$ Where: CL_A = compliance limit for fuel A CL_B = compliance limit for fuel B Q_A = heat input from fuel A Q_B = heat input from fuel B • Group I units – 5 ppmv by January 1, 2013 • Group II and Group III units at municipal sanitation service facilities – 9 ppmv until a Regulation XI rule referenced in paragraph (f)(5) is adopted or amended CO Emission limit @ 3% O_2: 400 ppmv	NOx emission limits @ 3% O_2: • Any units fired on landfill gas and cofired units firing natural gas and 90% landfill gas or more, and cofired unit firing up to 25% natural gas with landfill gas if only alternative is shutting down and flaring – 25 ppmv by January 1, 2015 • Weighted limit for landfill gas unit burning more than 25% natural gas: $\frac{(CL_A \times Q_A) + (CL_B \times Q_B)}{(Q_A + QB)}$ Where: CL_A = compliance limit for fuel A CL_B = compliance limit for fuel B Q_A = heat input from fuel A Q_B = heat input from fuel B • Natural gas fired units at municipal sanitation service facilities – 9 ppmv until a Regulation XI rule referenced in paragraph (f)(5) is adopted or amended CO Emission limit @ 3% O_2: 400 ppmv	NOx emission limits @ 3% O_2: • Boilers – 5 ppmv Ammonia: 5 ppmv (@ 3% O_2)	None
Reporting	Source testing. CEMS data every six months (Rule 218).	CEMS data every six months (Rule 218).	None	CEMS data every six months (Rule 218).	None
Monitoring	A continuous in-stack NOx monitor for units with a rated heat input capacity ≥ 40 MMBtu/hr and an annual heat input >	A continuous in-stack NOx monitor for units with a rated heat input capacity ≥ 40 MMBtu/hr and an annual heat input >	Source tests every 5 years. Diagnostic emission checks.	A continuous in-stack NOx monitor.	None

	200 x 10^9 Btu per year. Source testing every 3-5 years. Diagnostic emissions checks.	200 x 10^9 Btu per year. Source testing every 3-5 years. Diagnostic emissions checks.			
Recordkeeping	Monitoring data including CEMS, source tests, and diagnostic emission checks. Records of maintenance, service, tuning, startup and shutdown. Source test and diagnostic emission check required records. Records must be kept for 5 years.	CEMS maintenance and emission records for 2 years. Records of all source tests. Diagnostic emission check records for 2 years (5 years for Title V facilities).	Source tests and diagnostic emission checks for 2 years (5 for Title V facilities).	Operating log, monitoring data maintained for five years	None
Fuel Restrictions	None	None	None	Liquid petroleum fuel limited to Force Majeure natural gas curtailment, readiness testing, and source testing	

TABLE 4-7
PR 1150.3 COMPARATIVE ANALYSIS – TURBINES

Rule Element	PR 1150.3	Rule 1134	Rule 1135	40 CFR Part 60 GG	40 CFR Part 60 KKKK
Applicability	Located at an MSW landfill or landfill gas to energy facility: landfill gas and dual fuel turbines rated <0.3 MW and landfill gas, dual fuel, and other gaseous or liquid fuel turbines rated ≥0.3 MW.	Stationary gas turbines with ≥0.3 MW except those located electric generating facilities (Rule 1135), landfills, petroleum refineries, and publicly owned treatment works or fueled with landfill gas	Boilers, gas turbines, and diesel internal combustion engines on Santa Catalina Island that generate electric power located at investor-owned electric utilities, publicly owned electric utilities, or facilities with combined generation capacity of ≥ 50 MW excluding landfills, petroleum refineries, or publicly owned treatment works	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 exclusively landfill gas or dual fuel- 9 ppmv	NOx emission limits @ 15% O_2 by January 1, 2024:	NOx emission limits @ 15% O_2 by January 1, 2024:	NOx limit @ 15% O_2, where Y =	NOx limit @ 15% O_2: • ≤ 50 MMBtu/hr - 42 ppm new, firing

	on and after date of adoption • ≥ 3 MW with post-combustion control and firing ≥75% landfill gas – 25 ppmv on and after date of adoption • ≥ 3 MW without post-combustion control and firing ≥ 75% landfill gas– 12.5 ppmv on and after date of adoption • ≥ 3 MW with post-combustion control and firing ≥ 75% landfill gas – 12.5 upon turbine replacement • ≥ 0.3 MW and firing < 75% landfill gas – limit in paragraph (d)(2) on and after date of adoption: Weighted Limit= $\frac{(CL_A \times Q_A \times V_A) + (CL_B \times Q_B \times V_B)}{(Q_A \times V_A) + (Q_B \times V_B)}$ Where: CLA = compliance limit in Table 1 when firing 75% landfill gas or more QA = higher heating value of landfill gas in Btu per standard cubic foot (scf) VA = flow rate of landfill gas in scf per unit of time CLB = compliance limit in Table 1 when firing 100% natural gas QB = higher heating value of natural gas in Btu per scf VB = flow rate of natural gas in scf per unit of time • Combined cycle ≥ 3 MW and firing exclusively natural gas – 2 ppmv on and after date of adoption • Simple cycle ≥ 0.3 MW and firing exclusively natural	• Liquid fuel, located on outer continental shelf – 30 ppmv • Natural gas, combined cycle- 2 ppmv • Natural Gas, simple cycle- 2.5 ppmv • Produced gas- 9 ppmv • Produced gas, located on outer continental shelf – 15 ppmv • Other – 12.5 ppmv Ammonia (@ 15% O_2: 5 ppmv	• Combined Cycle Gas Turbine and Associated Duct Burner- 2 ppmv • Simple Cycle Gas Turbine- 2.5 ppmv Ammonia (@ 15% O2: 5 ppmv	Manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen: • 0.0075* (14.4/Y) +F •0.0150* (14.4/Y) +F SO_2 limit @15% O2: • 0.015% by volume	natural gas, electric generating • ≤ 50 MMBtu – 100 ppm new, firing natural gas, mechanical drive • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 25 ppm new, firing natural gas • >850 MMBtu/hr – 15 ppm new, modified, or reconstructed, firing natural gas • ≤ 50 MMBtu/hr – 96 ppm new, firing fuels other than natural gas, electric generating • ≤ 50 MMBtu/hr – 150 ppm new, firing fuels other than natural gas, mechanical drive • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 74 ppm new, firing fuels other than natural gas • >850 MMBtu/hr – 42 ppm new, modified, or reconstructed, firing fuels other than natural gas • ≤ 50 MMBtu/hr – 150 ppm modified or reconstructed • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 42 ppm modified or reconstructed, firing natural gas • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 96 ppm modified or reconstructed, firing fuels other than natural gas SO_2 limit:

	gas– 2.5 ppmv on and after date of adoption CO emission limit @15% O_2: 130 ppm				• 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. CEMS data every six months (Rule 218).	CEMS data every six months (Rule 218).	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. Source testing every 1-3 years.	A continuous in-stack NOx monitor for turbines with a capacity of 2.9 MW or greater. Source testing every 1-3 years.	A continuous in-stack NOx monitor	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.
Recordkeeping	Monitoring data including CEMS data, source tests, diagnostic emission checks, and an operating log. Maintenance, service, and tuning records. Records to demonstrate compliance with source test requirements. Required records must be maintained for 5 years.	Operating log, emission control system records of operation and maintenance for 2 years.	Operating log, monitoring data 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	Liquid fuel limited to turbines located in the outer continental shelf	Liquid petroleum fuel limited to Force Majeure natural gas curtailment, readiness testing, and source testing	None	None

APPENDIX A – LIST OF AFFECTED FACILITIES

Table A-1: Facilities Affected by PR 1150.3

Facility ID	Facility Name
140373	Ameresco Chiquita Energy LLC
113518	Brea Parent 2007, LLC
139865	City of Burbank/Water and Power
25070	LA Cnty Sanitation District- Puente Hills
42514	LA County Sanitation Dist (Calabasas)
113873	MM West Covina, LLC
139938	Sunshine Gas Producers, LLC

APPENDIX B – RESPONSES TO PUBLIC COMMENTS

Comment: Source testing schedules in Rule 1150.1 compliance plans should be an alternative to the source test schedule required in PR 1150.3.

Response: Rule 1150.1 does not regulate the same pollutants as PR 1150.3. 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: Clarification is needed on types of events that qualify as scheduled startup and shutdown events.

Response: Staff included examples of scheduled startup and shutdown events in Chapter 3 of the PR 1150.3 Staff Report.

Comment: PR 1150.3 should allow options besides a non-resettable hour meter to demonstrate hours of operation.

Response: Staff has revised the rule language to include an option for a South Coast AQMD approved alternative device which continuously records unit operating hours, in lieu of a non-resettable hour meter.

Comment: The South Coast AQMD Biogas Toolkit should not be used for cost-effectiveness analysis.

Response: Staff requested facility cost information to complete a revised incremental cost-effectiveness analysis. Staff has not received cost estimates for equipment of a comparable size to units subject to PR 1150.3. Without alternative cost information, staff will use the South Coast AQMD Biogas Toolkit for gas treatment cost estimates.

Comment: Turbine parts that are sent to the manufacturer and rebuilt should not be included in the definition of turbine replacement.

Response: Turbine replacement definition does not include turbine overhauls in which the original turbine unit returns to operation at the facility within 90 days.