SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report

Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities

Proposed Rule 429.2 – Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities

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CHAPTER 1: BACKGROUND

INTRODUCTION

Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (Rule 1135) applies to RECLAIM NOx, former RECLAIM NOx, and non-RECLAIM NOx electricity generating facilities that are investor-owned electric utilities, publicly owned electric utilities, or have a generation capacity of at least 50 megawatts of electrical power. Rule 1135 is needed for the transition of electricity generating facilities from NOx REgional CLean Air Incentives Market (RECLAIM) program to a command-and-control regulatory structure and implements Best Available Retrofit Control Technology (BARCT) for electric generating units.

Proposed amendments to Rule 1135 are needed to remove ammonia emission limits that will be addressed during permitting and remove startup and shutdown provisions that will be addressed in Proposed Rule 429.2 – Startup and Shutdown Exemption Provisions at Electricity Generating Facilities (PR 429.2), consistent with other source-specific rules. Additionally, Rule 1135 needs to be amended to reference the recently amended and adopted Rule 218-series rules for continuous emission monitoring systems (CEMS) requirements and modify NOx emission limits for diesel internal combustion engines on Catalina Island.

PR 429.2 is a companion rule to Rule 1135 and will provide exemptions from NOx concentration limits during startup and shutdown events to align with United States Environmental Protection Agency (U.S. EPA) policies for startup, shutdown, and malfunction events. Provisions in PR 429.2 will exempt electric generating units from Rule 1135 NOx emission limits and applicable rolling average provisions during startup and shutdown events and limit the duration of startup and shutdown events and the frequency of scheduled startups. Additionally, PR 429.2 establishes best management practices for startup and shutdown events as well as recordkeeping requirements.

REGULATORY BACKGROUND

Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities Rule 1135 was adopted in 1989 and applied to electric power generating steam boiler systems, repowered units, and alternative electricity generating sources. A NOx system-wide average emission limit and a daily NOx emissions cap was established for each utility system. Additionally, Rule 1135 required Emission Control Plans and continuous emissions monitoring systems (CEMS).

Rule 1135 was amended in December 1990 to resolve implementation and enforceability issues raised by the California Air Resource Board. This amendment included accelerated retrofit dates for emission controls, unit-by-unit emission limits, modified compliance plan and monitoring requirements, computerized telemetering, and an amended definition of alternative resources. Rule 1135 was amended again July 1991 to address additional staff recommendations regarding system-wide emission rates, daily emission caps, annual emission caps, oil burning, and cogeneration, along with outstanding issues related to modeling and BARCT analysis. U.S. EPA approved Rule 1135 into the State Implementation Plan (SIP) on August 11, 1998.

In 2018, Rule 1135 was amended to establish BARCT NOx limits which are needed to transition electricity generating facilities in the NOx RECLAIM program to a command-and-control regulatory structure and to implement Control Measure CMB-05 of the 2016 AQMP and AB 617. The 2018 amendment expanded Rule 1135 applicability to all electric generating units at RECLAIM NOx, former RECLAIM NOx, and non-RECLAIM NOx electricity generating facilities. The amendment updated emission limits to reflect current BARCT levels and to provide implementation timeframes for boilers, gas turbines, internal combustion engines located on Santa Catalina Island. Additionally, the amendment established provisions for monitoring, reporting, and recordkeeping, and exemptions from specific provisions.

Electricity Generating Facilities and RECLAIM

When RECLAIM was adopted in 1993, pursuant to Rule 2001 electricity generating facilities were initially included in NOx RECLAIM and could opt-in to SOx RECLAIM. In June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RECLAIM trading credit (RTC) prices for both the 1999 and 2000 compliance years. Based on the 2000 RECLAIM Annual Report, electricity generating facilities reported approximately 4,400 tons per year over their initial allocation. This was primarily due to an increased demand for power generation and delayed installation of controls by electricity generating facilities. The electric power generating industry purchased a large quantity of RTCs, which depleted the available RTCs. This situation was compounded because few RECLAIM facilities added control equipment. As a result, in May 2001, the Board adopted Rule 2009 – Compliance Plan for Power Producing Facilities (Rule 2009). Rule 2009 required installation of BARCT through compliance plans at electricity generating facilities.

Between 2001 and 2005, more than 35 simple and combined cycle gas turbines were repowered to BARCT levels or below. Despite the increase in NOx RTC demand, emissions from electricity generating facilities fell from 26 tons per day of NOx emissions in 1989 to less than 10 tons per day of NOx emissions by 2005. By 2017, with equipment replacement and increased reliance on renewable sources, NOx emissions had further decreased to less than 4 tons per day. With the most recent amendment to Rule 1135, NOx emissions from electricity generating facilities is expected to be 1.8 tons per day by January 1, 2024.

As part of the series of command-and-control rules to establish BARCT NOx emission limits and to facilitate the transition of the NOx RECLAIM program, several rules included an ammonia slip limit of 5 ppm for equipment with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR): 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134), 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, and 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146). Subsequently, staff decided that addressing ammonia limits during permitting is more appropriate to prevent conflicts with implementing Regulation XIII – New Source Review. South Coast AQMD Rule 1303 – Requirements requires Best Available Control Technology (BACT) for ammonia emissions if pollution control equipment, such as selective SCR or NSCR, is installed to meet a BARCT NOx limit and results in increased ammonia emissions of one pound per day or more. During permitting, the ammonia limit can be evaluated relative to the NOx limit in the rule and established at an achievable level for the equipment on a case-by-case basis.

Startup and Shutdown

Under the RECLAIM program, facilities are required to hold sufficient RECLAIM Trading Credits (RTCs) to reconcile actual emissions at the end of each annual compliance cycle, including the emissions that occur during startup and shutdown. A unit and/or associated control equipment is not operating under steady-state conditions during startup or shutdown, which may result in greater emissions. For example, during startup and shutdown of combustion equipment, the temperature of the unit and/or associated controls is in transition and requires the addition of excess air. This process results in increased NOx formation.

Under a command-and-control regulatory structure, an owner or operator is required to meet emission limits on each individual piece of equipment on a continuous basis. Consequently, units that can otherwise meet lower NOx emission limits during steady-state conditions, may be unable to do so during periods of startup and shutdown. Therefore, provisions are needed to exclude emissions that occur during startup and shutdown from compliance determination with rule emission limit(s). Currently, Rule 1135 exempts startup and shutdown from the NOx emission limits and requires each electric generating unit to include permit limits for duration, mass emissions, and number of start-ups, shutdowns by January 1, 2024. Additionally, many existing electric generating units currently have requirements for startup and shutdown in their permits. Startup, shutdown, and tuning are unique to each unit and evaluated during the permitting process. However, U.S. EPA recommended that startup and shutdown requirements be included in Rule 1135 to facilitate enforceability and ensure SIP approval.

U.S. EPA POLICY ON STARTUP, SHUTDOWN, AND MALFUNCTION

U.S. EPA issued startup, shutdown, and malfunction (SSM) policies in 2015 and 2020, which provided differing guidance on the requirements necessary for SIP approval. On September 30, 2021, U.S. EPA withdrew the 2020 policy and reinstated their prior 2015 policy, citing that the 2015 policy is more consistent with the Clean Air Act and relevant case law[1].

2015 Startup, Shutdown, and Malfunction State Implementation Plan Policy

In 2015, U.S. EPA issued a SSM SIP Policy (80 FR 33840; June 12, 2015) which stated that exemptions from emission limitations during startup and shutdown events and affirmative defense provisions were inconsistent with the federal Clean Air Act (CAA)[2]. U.S. EPA asserted that an emission limitation must be applicable to the source continuously to be permissible in a SIP pursuant to CAA section 302(k). U.S. EPA's 2015 SSM SIP Policy stated that SIP emission limitations do not need to be numerical in format, do not have to apply the same limitation (e.g. numerical level) at all times, and may include alternative numerical limitations, other technological control requirements, or work practice requirements during startup and shutdown events, so long as those components of the emission limitations meet applicable federal CAA requirements.

AFFECTED FACILITIES AND EQUIPMENT

There are 133 electric generating units at 32 electricity generating facilities that are potentially impacted by PAR 1135 and PR 429.2. Table 1-1 contains the equipment affected by PAR 1135 and PR 429.2.

[1] https://www.epa.gov/system/files/documents/2021-09/oar-21-000-6324.pdf
[2] https://www.govinfo.gov/content/pkg/FR-2015-06-12/pdf/2015-12905.pdf#page=2

Table 1-1: PAR 1135 and PR 429.2 Affected Equipment

Equipment Type	Number of Units
Boilers	17
Combined Cycle Gas Turbines	26
Combined Cycle Gas Turbine-Associated Duct Burners	11
Diesel Internal Combustion Engines	6
Simple Cycle Gas Turbines	73

PUBLIC PROCESS

Development of PAR 1135 and PR 429.2 was conducted through a public process. South Coast AQMD held two remote Working Group Meetings on May 28, 2021 and September 15, 2021. The Working Group is composed of representatives from affected facilities, environmental groups, public agencies, and consultants. The purpose of the Working Group Meetings is to discuss proposed concepts and work through the details of staff's proposals. A Public Workshop was held on October 27, 2021. Additionally, staff met individually with several facility operators.

CHAPTER 2: SUMMARY OF PROPOSAL FOR PROPOSED AMENDED RULE 1135

INTRODUCTION

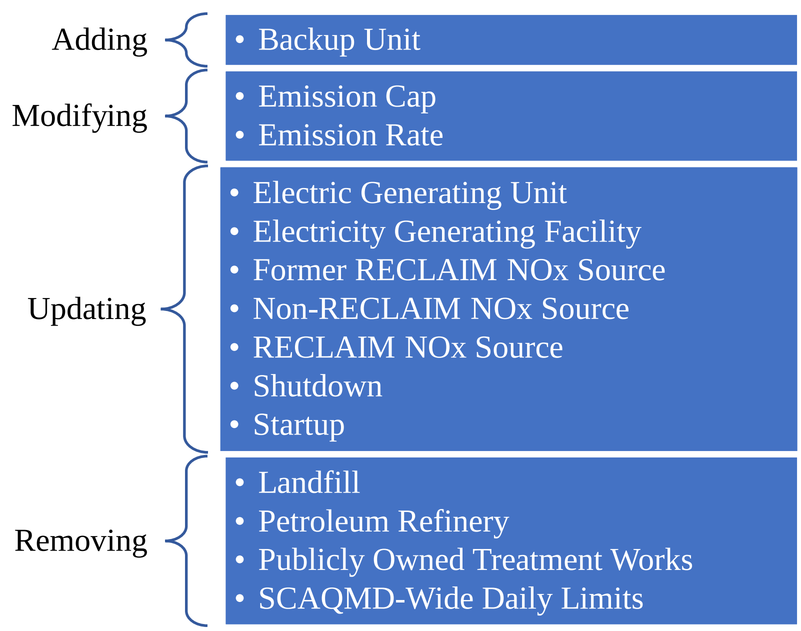
Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities (PAR 1135) will remove ammonia emission limits and move startup and shutdown provisions to Proposed Rule 429.2 – Startup and Shutdown Exemption Provisions at Electricity Generating Facilities (PR 429.2) to be consistent with policy changes that have been implemented after the last amendment of Rule 1135. Additionally, PAR 1135 will reference the recently amended and adopted Rule 218-series rules for continuous emission monitoring systems (CEMS) requirements. PAR 1135 also proposes to revise the NOx emission limits for diesel internal combustion engines and include other amendments to provide additional clarifications.

PROPOSED AMENDED RULE 1135

Definitions (Subdivision (c))

PAR 1135 includes new, modified, updated, and removed definitions, as listed in Figure 2-1.

Figure 2-1: Proposed Definition Revisions



Backup Unit (paragraph (c)(2))

PAR 1135 includes a provision, paragraph (e)(3), addressing monitoring, reporting, and recordkeeping requirements when NOx process units currently subject to Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions (Rule 2012) exit the RECLAIM program and become applicable to Rule 1135 monitoring, reporting, and recordkeeping requirements. A term for these units, "Backup Unit," is added and is defined as:

> *Any NOx emitting turbine which is used intermittently to produce energy on a demand basis, that does not operate more than 1,300 hours per year, is not subject to 40 CFR Part 72, and was a NOx process unit prior to the facility becoming a former RECLAIM NOx facility.*

This term is based on the definition of "NOx Process Unit" in Rule 2012 and "Peaking Unit" in Rule 2012 Attachment F – Definitions. Per Rule 2012 paragraph (e)(1) a "NOx Process Unit" is any NOx emitting equipment and includes "Peaking Units." Rule 2012 Appendix E defines "Peaking Unit" as a turbine used intermittently to produce energy on a demand basis and does not operate more than 1,300 hours per year. In addition, 40 CFR Part 72 (Acid Rain Program) is added into the definition since units in the Acid Rain Program are required to follow specific monitoring, reporting, and recordkeeping requirements. Lastly, the definition requires that Backup Units were categorized as NOx process units when in the RECLAIM program, which is added to ensure that no units that currently have CEMS utilize paragraph (e)(3).

Electric Generating Unit (paragraph (c)(8))

For clarification, the definition "Electric Generating Unit" is revised to exclude portable engines registered under the California Air Resources Board (CARB) Statewide Portable Equipment Registration Program (PERP). These engines are registered with CARB and are not required to obtain individual permits from local air districts and do not produce electrical power for distribution in the state or local electrical grid system.

Emission Cap, Emission Rate, and SCAQMD-Wide Daily Limits (paragraphs (c)(10) and (c)(11) and former paragraph (c)(20))

To streamline the rule language in paragraph (d)(6) for City of Glendale where emissions caps or emissions rates are required, "SCAQMD-Wide Daily Limits" is removed and the terms embedded within that definition, "Emission Cap" and "Emission Rate," are made their own definitions. In the "Emission Rate" definition, the provision regarding emissions from startup and shutdown is moved to the applicable requirement in clause (d)(6)(A)(i).

Electricity Generating Facility, Landfill, Petroleum Refinery, and Publicly Owned Treatment Works (paragraph (c)(9) and former paragraphs (c)(13), (c)(16), and (c)(18))

"Electricity Generating Facility" is updated to reference the applicable South Coast AQMD rules for landfills (Rule 1150.3 – Emissions of Oxides of Nitrogen from Combustion Equipment at Landfills), petroleum refineries (Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations), and publicly owned treatment works (Rule 1179.1 – Emission Reductions From Combustion Equipment at Publicly Owned Treatment Works Facilities) that are not applicable to Rule 1135. During the last amendment for Rule 1135, these rules were not yet adopted, so the rule language referenced the industry instead. With the updated "Electricity Generating Facility" definition, the definitions for "Landfill," "Petroleum Refinery," and "Publicly Owned Treatment Works" are obsolete and therefore removed.

Additionally, the definition of "Electricity Generating Facility" is clarified to say that only investor-owned electric utilities and publicly owned electric utilities with electric generating units falls under this definition. Electricity Generating Facilities do not include facilities that do not generate power such as garages, laydown yards, office buildings, service centers, substations, or warehouses of investor-owned electric utilities and publicly owned electric utilities.

Former RECLAIM NOx Source, Non-RECLAIM NOx Source, and RECLAIM NOx Source (paragraphs (c)(13), (c)(16), and (c)(19))

The terms "Former RECLAIM NOx Source," "Non-RECLAIM NOx Source," and "RECLAIM NOx Source" replaced "Source" with "Facility" and were aligned with the definitions in Rule 1100 – Implementation Schedule for NOx Facilities for consistency.

Shutdown and Startup (paragraphs (c)(20) and (c)(22))

PAR 1135 moves startup and shutdown provisions to PR 429.2, which will regulate startup and shutdown events for electric generating units. The "Shutdown" and "Startup" definitions are revised to reference PR 429.2 for the definition.

Emissions Limits (Subdivision (d))

Reference to Rule 2001 (paragraphs (d)(1) and (d)(3))

Rule 2001 – Applicability was last amended in July 2019 and one of the amendments was to update Table 1. Therefore, the rule language referencing Rule 2001 in paragraphs (d)(1) and (d)(3) are now obsolete and removed from PAR 1135.

Removal of Ammonia Limits (Tables 1 and 2)

As mentioned in Chapter 1, to align with policy changes regarding ammonia emissions, the ammonia emission limits in Table 1: Emissions Limits for Boilers and Gas Turbines and Table 2: Emissions Limits for Diesel Internal Combustion Engines are removed. Ammonia emission limits will now be addressed during permitting. For existing electric generating units, ammonia limits in their existing permits will be retained and will not be reassessed.

Electric Generating Units Located on Santa Catalina Island (paragraphs (d)(2) through (d)(4) and former paragraph (d)(4))

Southern California Edison (SCE) currently provides electric generation for Santa Catalina Island using six diesel internal combustion engines, with diesel fuel barged in from the mainland to the island as there is no infrastructure for natural gas. Currently Rule 1135 provides two compliance options for the electric generating units on Santa Catalina Island: 1) Meet a mass emission limit of 13 tons of NOx per calendar year annually by January 1, 2026 with an option of an extension up to three years, to be achieved by implementing near-zero or zero-emission technologies (former paragraph (d)(4)), or 2) If the first option is not feasible, meet the emission limits for diesel internal combustion engines in Table 2 by January 1, 2024 with an option of an extension up to three years.

After the adoption of the 2018 amendments to Rule 1135, SCE conducted a feasibility study[3] that evaluated near-zero and zero-emission technology options, which included renewable energy

[3] "Santa Catalina Island Repower Feasibility Study," authored by consulting group NV5 in partnership with the National Renewable Energy Laboratory and U.S. Environmental Protection Agency. https://www.sce.com/about-us/reliability/upgrading-transmission/catalina-repower

technologies (i.e., solar, wind turbines, wave power) and power supply from the mainland via an undersea cable. Due to limited fuel infrastructure, space, permitting, and land ownership considerations on the island, the feasibility study concluded that replacement of the engines with new U.S. EPA Tier 4 Final-Certified diesel engines was the most feasible option, which would allow SCE to meet the Rule 1135 emission limits in the near-term and to possibly integrate zero-emission technologies in the long-term.

At the Public Workshop held on October 27, 2021, staff presented that the NOx emission limit for diesel internal combustion engines would be maintained, but the rolling average would be revised from 60-minutes to 3-hours. A stakeholder commented that Rule 1135 requirements for diesel engines need to be re-evaluated and require a near-zero or zero-emission technology (e.g. fuel cells) as BARCT. The current Rule 1135 compliance options for diesel engines were based on the BARCT assessment conducted during the 2018 rule amendment, and thus, do not consider currently available zero-emission technologies, which have progressed since then. Staff is including a Resolution to conduct an updated BARCT assessment as soon as practicable for the electricity generating units on Santa Catalina Island.

To facilitate a pathway for SCE to evaluate and implement near-zero or zero-emission technologies on Santa Catalina Island, PAR 1135 makes the alternative compliance approach of meeting an annual mass emission limit from all electric generating units of 13 tons of NOx by January 1, 2026 in former paragraph (d)(4) the primary compliance approach. Paragraph (d)(2) will require the electricity generating facility on Santa Catalina Island to meet a mass emission limit from all electric generating units of 50 tons of NOx annually by January 1, 2024 (subparagraph (d)(2)(A)), not install or replace any diesel internal combustion engines after January 1, 2024 ((subparagraph (d)(2)(B)), meet a mass emission limit from all electric generating units of 45 tons of NOx annually by January 1, 2025 (subparagraph (d)(2)(C)), and meet a mass emission limit from all electric generating units of 13 tons of NOx annually on and after January 1, 2026 (subparagraph (d)(2)(D)). Currently, the definition for electric generating units does not include the new technology that will replace the engines, but the mass emissions will include emissions from these units. Once the new technology is determined, it will be integrated into the definition of electric generating unit. The annual mass emission limits of 50 and 45 tons of NOx are interim limits that allows the facility to achieve emission reductions upfront with feasibly-determined near-term solutions, which can include engine replacement, as the facility evaluates options to achieve near-zero or zero-emission technology to power the island by January 1, 2026. Additionally, to ensure that near-zero or zero-emission technology will be installed on the island, subparagraph (d)(2)(B) will prohibit the installation of any new diesel internal combustion engines after January 1, 2024. This prohibition refers to electric generating units and does not include emergency diesel internal combustion engines or portable engines registered under PERP. Additionally, this prohibition does not include diesel internal combustion engines that are undergoing reconstruction as defined in 40 CFR Part 60.15 or Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines; all other existing reconstruction requirements are still applicable. The mass emission limits from all electric generating units in subparagraph (d)(2)(A), (d)(2)(C), and (d)(2)(D) include mass emissions from startups and shutdowns. Paragraph (d)(3) requires the mass emissions limits in Table 2 on and after January 1, 2024 for new diesel internal combustion engines that are installed to comply with mass emission limits in subparagraph (d)(2)(A), (d)(2)(C), and (d)(2)(D).

Current Table 2 specifies that diesel internal combustion engines meet a NOx emission limit of 45 ppmv at 15 percent oxygen, averaged over a 60-minute rolling average. This limit was derived from the U.S. EPA's Regulation for Emissions from Heavy Equipment with Compression-Ignition (Diesel) Engines Tier 4 Final emission standard of 0.67 g/kWh or 0.50 g/bhp-hr with an assumed engine efficiency of 40 percent. To determine an engine's NOx emissions, the Tier 4 Final certification test measures the NOx emissions at five different operating loads (10, 25, 50, 75, and 100 percent) and then averages those results.

Based on discussions with SCE, the replacement engines planned for installation, if they were to meet the compliance option of all diesel engines meeting the emissions limits in the current Table 2 by January 1, 2024, are three different engine sizes: 1) 2,200 bhp engine driving a 1,365 kW generator, 2) 3,280 bhp engine driving a 1,825 kW generator, and 3) 4,060 bhp engine driving a 2,500 kW generator.

The replacement engines meet the emissions limits in Table 2 of the rule except for the 45 ppmv NOx emission limit at certain loads. Based on test data provided by the manufacturer, these replacement engines cannot meet NOx emission limit under two test loads. The first is for the 2,200 bhp engine driving a 1,365 kW generator and 3,280 bhp engine driving a 1,825 kW generator, at 10 percent load. The second is for the 4,060 bhp engine driving a 2,500 kW generator at 100 percent load. However, the manufacturer indicated that these replacement engines can meet 45 ppmv NOx at all other tested loads. Since the engines do not normally operate at loads below 10 percent or at 100 percent load, there are only short periods of time when the engine would have higher emissions.

Paragraph (d)(3) requires that engines meet the 45 ppmv NOx emission limit on a continuous basis averaged over 60 minutes. To address this issue of the two instances where the replacement engines cannot meet 45 ppmv NOx, PAR 1135 revises the rolling average period for the 45 ppmv NOx emission limit from 60 minutes to three hours. The shorter averaging period could result in excessive restarting of the new engines when the NOx emissions start to approach the emission limit and consequently result in higher NOx emissions and make providing continuous power to Santa Catalina Island challenging. As the limit is still 45 ppmv at 15 percent oxygen, no NOx emission increases are expected.

For clarification of the emission averaging methods to be used to demonstrate compliance with the NOx emission limit, Footnote 1 in Table 2 specifies that the three-hour rolling average be calculated using hourly averages computed in accordance with Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications (Rule 218.3). Emission data averaging methods for compliance demonstration for intervals greater than one hour are specified in Rule 218.3 (March 5, 2021) subparagraphs (i)(4)(A) and (i)(4)(C).

Lastly, for consistency with the test methods required to certify diesel engines to the Tier 4 Final particulate matter (PM) emission standard pursuant to 40 CFR Part 1065 – Engine-Testing Procedures and the required test methods pursuant subparagraph (e)(5)(B), PAR 1135 adds a footnote to Table 2 clarifying that the 0.0076 lbs/MMbtu particulate matter emission limit applies to both filterable and condensable particulate matter.

Due to PAR 1135 making the annual mass emission limit of 13 tons of NOx by January 1, 2026 the primary compliance approach, former paragraph (d)(4) is removed.

Paragraph (d)(4) retains the option to request a time extension up to three years for the annual mass emission limit of 13 tons of NOx, but removes that option for all engines to meet the emissions limits in Table 2 as this requirement is no longer a compliance option. All references to former paragraph (d)(2) are removed in this paragraph. Now that PAR 1135 requires the facility on Santa Catalina Island to meet the 50-ton annual mass emission limit by January 1, 2024, the 45 ton annual mass emission limit by January 1, 2025, and the 13-ton annual mass emission limit by January 1, 2026, phased emission reductions required in clauses (d)(4)(A)(i) and (d)(4)(A)(ii) to qualify for a time extension and clause (d)(4)(E)(i), which requires an application to be submitted for a permit condition if the facility elects to the comply with the 13-ton annual mass emission limit, are no longer needed and are removed. Subclause (d)(4)(A)(ii)(D) adds a requirement for the time extension request to include a description of the technologies that will be used to achieve the 13-ton annual mass emission limit.

Start-up, Shutdown, and Tuning Requirements (former paragraph (d)(3))

PAR 1135 removes startup and shutdown provisions in paragraph (d)(3) which will now be addressed in PR 429.2.

Startup, Shutdown, and Tuning Requirements (paragraph (d)(5))

The provision now states that NOx emission limits from Table 1 and NOx, carbon monoxide, and volatile organic compounds emissions limits in Table 2 do not apply during startup and shutdown, but instead are applicable to Rule 429.2. Additionally, tuning will not be subject to Rule 1135 limits if the unit's Permit to Operate has limits for duration and number of tunings.

City of Glendale (paragraph (d)(6))

The provision regarding startup and shutdown emissions in the "Emissions Rate" definition (former subparagraph (c)(20)(B)) is moved to the emission rate requirement in clause (d)(6)(A)(i).

Permit Application Submittals (paragraphs (d)(6) through (d)(8))

The Rule 1135 permit application requirement in paragraph (d)(6) is amended to be applicable to only RECLAIM and former RECLAIM NOx facilities, excluding the electricity generating facility on Santa Catalina Island. Paragraph (d)(7) will be the permit application requirement for non-RECLAIM facilities, which will require submittals by January 1, 2023; this extended date is for permit submittals only and does not extend the Table 1 compliance date. One Rule 1135 non-RECLAIM facility is waiting for their city council to approve their repower project, which is anticipated to occur approximately at the end of January 2022. The permit application submittal date extension allows the facility enough time to submit their applications after a decision is made. Paragraph (d)(8) adds a new permit submittal deadline for Santa Catalina Island and requires applications for a change in permit conditions or for a Permit to Construct by January 1, 2023. Due dates for permit application submittals will ensure that South Coast AQMD staff will have enough time to process the permits before the Table 1 and Table 2 compliance dates. Permit application submittals required in paragraphs (d)(6) through (d)(8) pertain to changes to permit conditions that are needed to align with Rule 1135 requirements (e.g. revising the permit NOx emission limit of a boiler from 7 ppmv to 5 ppmv to be effective January 1, 2024, referencing specific Rule 1135 provisions for monitoring, recordkeeping, and reporting requirements). A facility does not need to submit a permit application for reconciliation if the current permit is already reconciled with Rule 1135.

Monitoring, Recordkeeping, and Reporting (Subdivision (e))

Former RECLAIM NOx and Non-RECLAIM NOx Facilities (paragraph (e)(2) and former paragraph (e)(3))

In March 2021, South Coast AQMD Rule 218-series rules addressing Continuous Emissions Monitoring Systems (CEMS) were amended and adopted to align CEMS requirements for former RECLAIM and non-RECLAIM facilities. As RECLAIM facilities exit the RECLAIM program, these facilities will be transitioned from South Coast AQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions (Rule 2012) to Rules 218.2 – Continuous Emission Monitoring System: General Provisions (Rule 218.2) and 218.3 – Continuous Emissions Monitoring System: Performance Specifications (Rule 218.3). Additionally, non-RECLAIM facilities will be transitioned from Rules 218 – Continuous Emission Monitoring (Rule 218) and 218.1 – Continuous Emission Monitoring Performance Specifications (Rule 218.1) to Rules 218.2 and 218.3. Paragraph (e)(2) now specifies that former RECLAIM NOx and non-RECLAIM NOx facilities follow Rules 218.2 and 218.3 and removes all Rule 2012 references. Former paragraph (e)(3) containing CEMS requirements for non-RECLAIM NOx sources is also removed. Rules 218.2 and 218.3 provide an implementation schedule for facilities operating CEMS previously certified to Rules 218 and 218.1 or Rule 2012. Therefore, requirements to follow 40 CFR Part 75 – Continuous Emission Monitoring and Rules 218 and 218.1 are retained and moved to paragraph (e)(2) until the applicable implementation dates set forth in Rules 218.2 and 218.3.

Backup Units (paragraph (e)(3))

Staff has identified one RECLAIM NOx facility that operates two turbines, which are currently NOx process units in the facility's RECLAIM/Title V Permit. Rule 2012 does not require process units to have a CEMS installed. Furthermore, the two units are simple cycle turbines each rated less than 25 megawatts and installed before November 15, 1990, making them not subject to the Acid Rain Program under 40 CFR Part 72 – Permits Regulation, which requires electric generating units to conduct continuous emission monitoring pursuant to 40 CFR Part 75.

Currently, Rule 1135 requires CEMS for all electricity generating units at former RECLAIM NOx and non-RECLAIM NOx facilities. Once a facility exits RECLAIM, units that were RECLAIM NOx process units, referred to as "Backup Units" in PAR 1135, will be required to have a CEMS. PAR 1135 maintains this requirement and will require former RECLAIM NOx facilities to follow Rule 218-series rules and operate CEMS. To allow sufficient time to implement Rule 218-series rules for the backup units after exiting RECLAIM, PAR 1135 will allow the backup units until July 1, 2026 to install CEMS, provided that the owner or operator does the following for each backup unit:

1) (subparagraph (e)(3)(A)) Measure quarterly fuel usage by installing, maintaining, and operating a totalizing fuel meter or any device approved by Executive Officer to be

equivalent in accuracy, reliability, reproducibility, and timeliness. Fuel usage is necessary to calculate the NOx emissions by multiplying the fuel usage by the emission factor specified in the Permit to Operate;

2) (subparagraph (e)(3)(B)) Demonstrate compliance with permit limits by conducting annual source testing using the following test methods: South Coast AQMD Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling, South Coast AQMD Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources, U.S. EPA Method 20 – Nitrogen Oxides from Stationary Gas Turbines, or U.S. EPA Method 7E – Nitrogen Oxide – Instrumental Analyzer;
3) (subparagraph (e)(3)(C)) Conduct the first source test either within six months from the time the facility becomes a former RECLAIM NOx facility or within one year from the date of the last source test, whichever is later;
4) (subparagraph (e)(3)(D)) At least 60 days before the scheduled source test date, submit a source test protocol to the Executive Officer for written approval. Source test protocols establish procedures to ensure results are accurate and representative of a source's emissions. The source test protocol must contain:
    a. Descriptions of the unit to be tested and process, including maximum and normal operating temperatures, pressures, and throughput;
    b. Operating conditions, such as operating turbine loads and test duration at each load, under which the source test will be conducted;
    c. Planned sampling parameters, including a process schematic diagram showing the ports and sampling locations, with the dimensions of ducts and stacks at the sampling locations and distances of flow disturbances (e.g. elbows, tees, fans, dampers) from the upstream and downstream sampling locations;
    d. Description of test, sampling, and analytical methods used to measure NOx, temperature, flow rates, and moisture;
    e. Description of calibration and quality assurance procedures; and
    f. Information on equipment, logistics, personnel, and other resources necessary to conduct an efficient and coordinated source test;
5) (subparagraph (e)(3)(E)) In lieu of submitting a source test protocol, the facility may use a previously approved source test protocol if: the unit has not been altered to where a permit modification is required; the permit NOx emission factors or concentration limits or equipment-specific or category-specific NOx emission rates have not changed since the previous test; and the approved source test protocol is representative of the operation and configuration of the unit, meets the source test protocol requirements provided in subparagraph (e)(3)(D), and references the test method required in subparagraph (e)(3)(B);
6) (subparagraph (e)(3)(F)) Within 30 days after the end of the first three quarters and 60 days after the end of the fourth quarter of the compliance year, submit a quarterly report of NOx mass emissions to the Executive Office, using a South Coast AQMD-approved format, as calculated using the emission factor specified in the Permit to Operate;
7) (subparagraph (e)(3)(G)) Annually tune-up according to the manufacturer's specifications;
8) (subparagraph (e)(3)(H)) Maintain records on-site for 5 years and make available to South Coast AQMD upon request: data collected and calibration records from the totalizing fuel meter or the South Coast AQMD-approved device; source test protocols and reports;

quarterly NOx mass emission reports, including the data used to calculate the NOx mass emissions; and each tune-up; and

9) (subparagraph (e)(3)(I)) Within six months of becoming a former RECLAIM NOx facility, submit a permit application to limit the total annual operation time of the backup unit to no more than 1,300 hours per year to ensure only backup units, as defined in PAR 1135, can utilize this provision.

The proposed requirements for backup units in lieu of installing and operating CEMS are the current monitoring, recordkeeping, and reporting requirements for these units. The requirements are specified in the facility's current Title V/RECLAIM permit and are pursuant to Rule 2012 subdivision (e) – NOx Process Unit.

<u>*Diesel Internal Combustion Engines (paragraph (e)(5))*</u>

Submitting a source test protocol for South Coast AQMD approval is the first step of source testing. For consistency with paragraph (e)(3), PAR 1135 paragraph (e)(5) adds source test protocol submittal requirements for source testing of diesel internal combustion engines. Subparagraph (e)(5)(C) references subparagraph (e)(3)(D) for the information to be included in the source test protocol. Subparagraph (e)(5)(D) references subparagraph (e)(3)(E) for the option to use a previously approved source test protocol in lieu of submitting a new protocol.

<u>*Catalytic and Non-Catalytic Control Devices with Ammonia Injection (paragraph (e)(6))*</u>

Currently, Rule 1135 only refers to source testing or continuous monitoring of ammonia for catalytic control devices. PAR 1135 paragraph (e)(6) adds non-catalytic control devices with ammonia injection to ensure source testing or continuous monitoring of ammonia emissions requirements apply to all electric generating units that emit ammonia.

<u>*Operations Recordkeeping (paragraph (e)(8))*</u>

Several stakeholders mentioned that this provision requires operators to keep multiple and redundant logs as operators are already required to keep logs of operating information by other rules or regulations. The provision is revised only to require records and does require not a separate operating log. Data generated by a Data Acquisition Handling System (DAHS) that sufficiently provides any of the information required in this paragraph can be used as records. Additionally, paragraph (e)(8) removes the provision requires that the records be maintained in a manner that is approved by the South Coast AQMD; approval will add additional burden on the facility and on the compliance inspector.

Use of Liquid Petroleum Fuel (Subdivision (f))

<u>*Distillate Fuel Oil Readiness Testing (paragraph (f)(2))*</u>

References to "fuel oil" are changed to "distillate fuel oil" to capture both diesel and fuel oils.

<u>*Source Testing and Fuel Flow Meter Calibration (paragraph (f)(3))*</u>

Some Rule 1135 electric generating units are permitted to perform annual fuel flow meter calibration in lieu of Relative Accuracy Test Audits (RATAs) during distillate fuel oil readiness testing or force majeure natural gas curtailment when the use of liquid petroleum fuel is required. Therefore, paragraph (f)(3) includes annual fuel flow meter calibration as a circumstance in which an electric generating unit is allowed to burn liquid petroleum fuel. Additionally, paragraph (f)(3) allows RATA tests and annual fuel flow calibration to be conducted concurrently with either distillate fuel oil readiness testing or during force majeure natural gas curtailment when the use of liquid petroleum fuel is required.

Exemptions (Subdivision (g))

Once-Through-Cooling Electric Generating Units to Be Retired (paragraph (g)(2))

Current Rule 1135 exempts once-through-cooling electric generating units that are subject to the Clean Water Act Section 316(b) from the emissions limits in paragraph (d)(1) under the conditions that the units keep their NOx and ammonia limits, startup, shutdown, and tuning requirements, and averaging times on the current permit and the units comply with their compliance dates established pursuant to Table 1 of Section 2(B) of the State Water Resources Control Board's Statewide Water Quality Control Policy on the Use of Coastal Estuarine Waters for Power Plant Cooling (Once-Through-Cooling Policy) implementing Section 316(b) of the Clean Water Act. This exemption was included with the understanding that the electric generating units subject to the Once-Through-Cooling Policy were scheduled for shutdown or retirement by these compliance dates. However, industry representatives notified staff that some once-through-cooling electric generating units may no longer be retired and only have their once-through-cooling systems removed. PAR 1135 paragraph (g)(2) clarifies that the exemption from paragraph (d)(1) applies to once-through-cooling units to be retired and requires in subparagraph (g)(2)(A) that the owner or operator must retire the unit by the compliance date established in the Once-Through-Cooling Policy to qualify for the exemption. Former subparagraph (g)(2)(D), which states that the owner or operator just comply with the compliance date established in the Once-Through-Cooling Policy, is removed to minimize duplication with subparagraph (g)(2)(A). An owner or operator of a once-through-cooling unit that will just remove the once-through-cooling system to comply with the policy are expected to comply with the emissions limits in paragraph (d)(1). Additionally, the exemption will now have a sunset date of December 31, 2029. This provision limits the amount of time that these units are allowed operate with NOx emissions greater than the NOx emission limits in Table 1.

CHAPTER 3: SUMMARY OF PROPOSAL FOR PROPOSED RULE 429.2

INTRODUCTION

PR 429.2 will establish startup and shutdown provisions for Rule 1135 electricity generating facilities. PR 429.2 will exempt electric generating units from Rule 1135 NOx emission limits during startup and shutdown events and establish startup and shutdown duration and frequency provisions. Additionally, PR 429.2 establishes best management practices during startup and shutdown events and recordkeeping requirements.

PROPOSED RULE 429.2

Purpose (Subdivision (a))

The purpose of this rule is to provide an exemption from Rule 1135 emission limits during periods when electric generating units are starting up and shutting down and establish requirements during startup and shutdown events. PR 429.2 is needed to regulate startup and shutdown pursuant to U.S. EPA SSM SIP Policy (80 FR 33840; June 12, 2015) regulating startups, shutdowns, and malfunctions.

Applicability (Subdivision (b))

PR 429.2 applies to an owner or operator of electric generating units subject to Rule 1135.

Definitions (Subdivision (c))

PR 429.2 incorporates definitions from Rule 1135 and other South Coast AQMD startup and shutdown rules to be proposed or amended as well as new definitions specific to the proposed rule. Please refer to PR 429.2 subdivision (d) for each definition.

Proposed Definitions:

- Electric Generating Unit
- Electricity Generating Facility
- Minimum Operating Temperature
- NOx Post-Combustion Control Equipment
- Oxides of Nitrogen (NOx) Emissions
- Scheduled Startup
- Shutdown
- Stable Conditions
- Startup

<u>*Startup and Shutdown (paragraphs (c)(9) and (c)(7))*</u>

To develop the definitions for startup and shutdown, staff modified “Startup” and “Shutdown” definitions in Rule 1135 to fit all equipment types subject to Rule 1135. Staff reviewed startup and shutdown definitions in current permits and worked with stakeholders to address concerns.

“Startup” is defined as:

> *The time period beginning when an electric generating unit begins combusting fuel after a period of zero fuel flow.*

Combusting fuel after a period of zero fuel flow could mean initial firing of fuel in the gas turbine combustors or to the burner in a boiler, or when fuel is first sprayed into the hot compressed air at a measured rate to ignite the fuel in a diesel engine. Since PR 429.2 will limit the duration of startups in paragraphs (d)(2), (d)(3), and (d)(4), the ending of a startup will be imposed as when the time limit specified in these paragraphs is reached.

"Shutdown" is defined as:

> *The time period that begins when an electric generating unit begins reducing load in advance of terminating fuel flow and ends in a period of zero fuel flow. For dual fuel electric generating units, a shutdown does not include the time period when the unit transitions from one fuel to another.*

Shutting down an electric generating unit starts by reducing load, which results in reduced combustion temperature, lower stack flow rate, and increased NOx formation. For units with NOx post-combustion control, the control equipment does not work when exhaust temperatures drop below minimum operating temperatures of the control equipment. Load reduction as a result of load fluctuation for power demand does not constitute the beginning of a shutdown. The ending of a shutdown is generalized as when there is a period of zero fuel flow, which means the unit is no longer combusting fuel. A period of zero fuel flow could mean cessation of firing in the gas turbine combustors, the fuel is shut off to the burner in a boiler or to the compressed air cylinder in a diesel engine, the flame signal of the gas turbine indicates the unit is offline, or the boiler is put into hot standby. Hot standby refers to when the igniters are on and fuel flow is minimal, but no electricity is being generated. For dual fuel electric generating units, when units are transitioning from one fuel to the other, there may be a short period of zero fuel flow. Therefore, the definition clarifies that this transition is not considered a shutdown.

Scheduled Startup (paragraph (c)(6))

PR 429.2 limits the frequency of scheduled startup events in paragraphs (d)(5) and (d)(6). Since electric generating units need to start up at any moment in time and may startup several times per day to meet energy demand without prior notice, only scheduled startups are limited in frequency. Staff modified the definition for "Scheduled Startup" from Rule 429 – Start-up and Shutdown Exemption Provisions for Oxides of Nitrogen to include types of startup events specific to electricity generating facilities that would not be considered scheduled and defined "Scheduled Startup" as:

> *A planned startup that is specified by January 1 of each year. A scheduled startup does not include a startup to meet energy demand, perform unplanned maintenance, or correct equipment failure, breakdown, or malfunction.*

Scheduled startups include, but are not limited to, startups due to planned maintenance, turnaround (catalyst changeout), source testing, tuning, diesel readiness testing, system reliability testing, regulatory testing, or construction. A startup is only considered a scheduled startup if it is known and specified by January 1 of each year.

NOx Post-Combustion Control Equipment (paragraph (c)(4))

PR 429.2 proposes various requirements for NOx post-combustion control equipment and is defined as:

> *Air pollution control equipment which eliminates, reduces, or controls the issuance of NOx downstream of combustion.*

This definition is modified from the Rule 102 – Definition of Terms definition of control equipment and made specific to NOx and post-combustion control equipment.

Minimum Operating Temperature and Stable Conditions (paragraphs (c)(3) and (c)(8))

PR 429.2 proposes various requirements to minimize emissions during startup and shutdown events. To provide clarification for the definition of shutdown (paragraph (c)(7)) and compliance determination with paragraphs (d)(4), (d)(9), and (e)(2), which ensure that NOx post-combustion control equipment are operating efficiently and effectively, a definition for "Minimum Operating Temperature" is defined as:

> *The minimum operating temperature specified by the manufacturer, or as otherwise defined in the South Coast AQMD Permit to Construct or Permit to Operate.*

To provide clarification for compliance determination with paragraph (d)(4), which ensures that electric generating units no longer exceed Rule 1135 emission limits once stable conditions is reached, a definition for "Stable Conditions" is added and is defined as:

> *The fuel flow to an electric generating unit is consistent and allows for normal operations.*

Requirements (Subdivision (d))

PR 429.2 establishes provisions for startup and shutdown duration, frequency of scheduled startups, and best management practices during startup and shutdown events. To synchronize these requirements with the current requirement in Rule 1135, PR 429.2 establishes an effective date of January 1, 2024 for many of the startup and shutdown provisions.

Exemption from Rule 1135 (paragraph (d)(1))

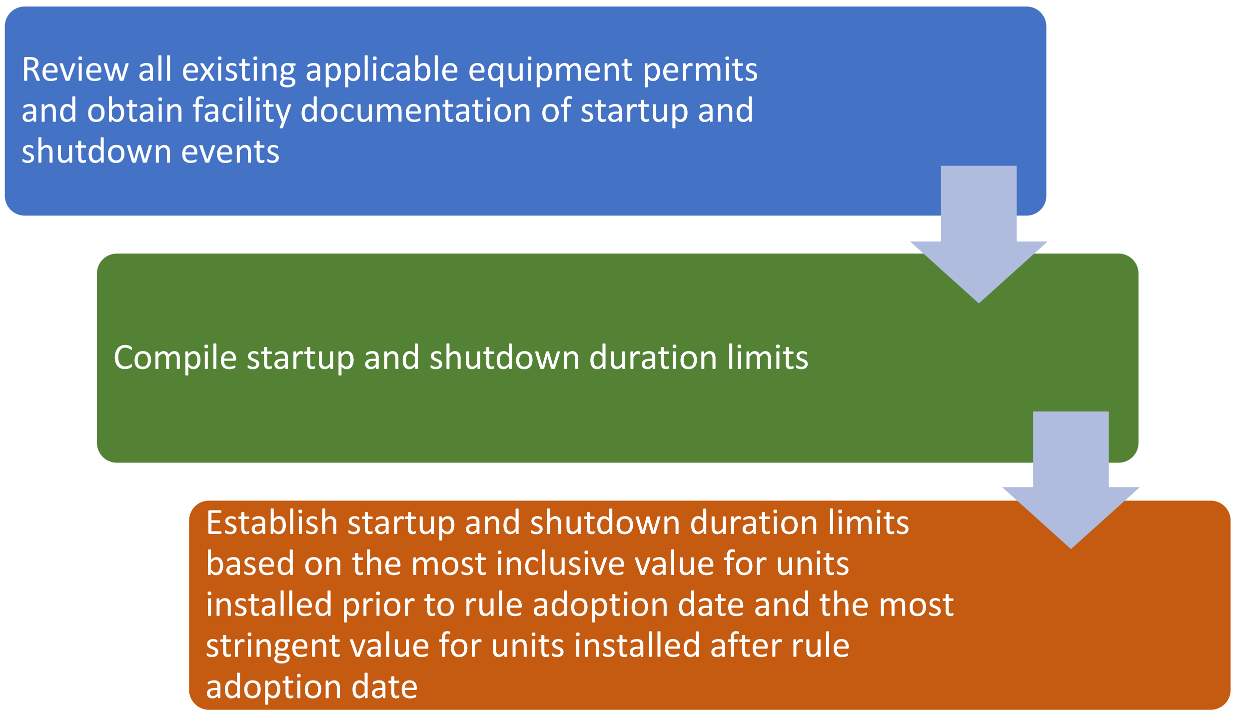
Paragraph (d)(1) specifies that Rule 1135 emission limits in Tables 1 and Table 2 do not apply during startup and shutdown. This exemption is necessary because NOx post-combustion control equipment cannot be utilized until an electric generating unit is at specific conditions and is stable. However, during startup and shutdown events, an owner or operator of an electric generating unit will be subject to the provisions in PR 429.2. For facilities with Rule 1135 mass emission limits, mass emissions from startups and shutdowns will be included when demonstrating the facility's annual mass emission; facilities are only being exempt from the Rule 1135 NOx concentration limit during startup and shutdown.

Startup and Shutdown Duration Limits (paragraphs (d)(2), (d)(3), and (d)(4))

To limit the exceedance of the Rule 1135 emissions limits during startup and shutdown, PR 429.2 requires that the startup and shutdown of an electric generating unit not exceed a time duration. PR 429.2 establishes two sets of startup and shutdown duration limits based on the date of installation of the electric generating unit.

To establish the duration limits, staff reviewed existing duration limits established in permits and any available facility data documenting startup and shutdown events. Staff then compiled these limits and established startup and shutdown duration limits for each equipment type based on two types of values: the most inclusive value and the most stringent value. The most-inclusive duration limit would apply to existing units. The existing units in an equipment category have major variations or outliers for startup or shutdown duration, due to factors such as equipment age or complexity of the equipment configuration. The most-stringent duration limit would apply to new units and ensures that new units do not follow less stringent startup and shutdown duration limits. Figure 3-1 summarizes the approach for establishing startup and shutdown duration limits.

Figure 3-1: Approach for Establishing Startup and Shutdown Duration Limits



Effective January 1, 2024, paragraph (d)(2) establishes startup and shutdown duration limits for electric generating units installed prior to the rule adoption date. PR 429.2 Table 1 (Table 3-1 in Staff Report) contains the startup and shutdown duration limits for each equipment type.

Table 3-1: Startup and Shutdown Limits for Electric Generating Units Installed Prior to Date of Rule Adoption

Equipment Type	Time Allowance	
	Startup	Shutdown
Boiler	20 hours	12 hours
Combined Cycle Gas Turbine and Associated Duct Burner	6 hours	2 hours
Simple Cycle Gas Turbine	1 hour	45 minutes
Diesel Internal Combustion Engines	1 hour	30 minutes

Effective upon rule adoption, paragraph (d)(3) establishes startup and shutdown duration limits for electric generating units installed on or after the rule adoption date. PR 429.2 Table 2 (Table 3-2 in Staff Report) contains more stringent startup and shutdown duration limits than Table 1 in paragraph (d)(2) for each equipment type since these units will be newer technology with faster startup and shutdown times. No startup or shutdown duration limits for boilers are proposed due to the expectation that there would be no new boilers as electricity generating facilities are choosing to repower old units with gas turbines, which have faster startup times, smaller footprints, and lower operating and maintenance costs. The duration limits for units installed on or after the rule adoption date are intended for natural gas fired equipment. If other fuels (e.g. hydrogen) were utilized, the limits would need to be reassessed in a future rule amendment.

Table 3-2: Startup and Shutdown Limits for Electric Generating Units Installed On or After Date of Rule Adoption

Equipment Type	Time Allowance	
	Startup	Shutdown
Combined Cycle Gas Turbine and Associated Duct Burner	60 minutes	30 minutes
Simple Cycle Gas Turbine	15 minutes	10 minutes
Diesel Internal Combustion Engines	30 minutes	30 minutes

If a unit has permit conditions which specify more stringent startup or shutdown duration limits than PR 429.2, the unit must follow the limits in the permit conditions. Situations where the owner or operator of a unit has initiated a startup of a unit but then has to shut down the unit (i.e., an aborted startup) and start up the unit again, will be addressed in the permit conditions of the unit. Additionally, startup duration limits established in paragraphs (d)(2) and (d)(3) also apply to scheduled startups.

Effective January 1, 2024, to further limit exceedances of the Rule 1135 emission limits, paragraph (d)(4) requires that startup times cannot last longer than the time necessary to reach stable conditions and minimum operating temperature and full deployment of the NOx post-combustion control, if applicable; all three conditions need to be met in order for the startup period to be over. Stable conditions are only determined after all startup procedures for a unit are complete. If a unit reaches stable conditions, the minimum operating temperature of the NOx post-combustion control equipment is reached, and all post-combustion NOx control equipment and processes, including water injection and dry low-NOx technology, are fully deployed, if applicable, before reaching the startup duration limit specified in paragraphs (d)(2), (d)(3), the Permit to Construct, or the Permit to Operate, whichever is the most stringent startup duration limit, the startup period is considered to be over, and the unit is required to meet applicable Rule 1135 emission limits. Parameters for establishing stable conditions include, but are not limited to, ammonia injection, normal operating mode, normal burner firing pattern, minimum operating load, and specific equipment temperatures.

Limit to the Number of Scheduled Startups (paragraphs (d)(5) and (d)(6))

Effective January 1, 2024, paragraph (d)(5) limits the number of scheduled startups to 12 events per calendar year for each electric generating unit that is not permitted perform distillate fuel oil readiness testing. For electric generating units permitted to perform distillate fuel oil readiness testing, paragraph (d)(6) limits the number of scheduled startups to 64 events per calendar year. The requirement to perform distillate fuel oil readiness testing can be up to one time per week, therefore, these units are allowed an additional 52 startups. Limitations to the number of scheduled startups is an existing requirement in Rule 429 and is carried forward into PR 429.2. Furthermore, limiting the frequency of scheduled startups provides additional bounds to the startup and shutdown provisions. Since electric generating units undergo much more frequent unscheduled startups than scheduled startups, the maximum number of scheduled startups is limited to twelve. Unscheduled startups are not limited by PR 429.2 because they may be driven by operational demand dependent on energy grid requirements, emergencies, or maintenance needs. The number of scheduled startups will count toward the number of total startups; The number of scheduled startups is not in addition to the number of total startups.

General Duty Requirements (paragraph (d)(7))

Upon rule adoption, paragraph (d)(7) requires that an owner or operator of an electric generating unit that exceeds applicable Rule 1135 emission limits during startup and shutdown events to take all reasonable and prudent steps to minimize emissions to meet applicable emission limits. This provision was modified from an existing Rule 429 provision. Reasonable and prudent steps to minimize emissions include, but are not limited to, equipment repairs and adjusting the temperatures of post-combustion controls.

Requirements for Units with NOx Post-Combustion Control Equipment (paragraphs (d)(8) and (d)(9))

Effective January 1, 2024, paragraph (d)(8) requires each electric generating unit with NOx post-combustion control equipment to install and maintain a temperature measuring device that is calibrated annually at the inlet of the NOx post-combustion control equipment. The operator is not required to install another temperature device and is only required to maintain the temperature device if one is already installed at the inlet of the NOx post-combustion control equipment. Temperature measuring devices include thermocouples and temperature gauges. Most existing units with NOx post-combustion control equipment are already equipped with temperature measuring devices. It is standard practice to include a temperature measuring device requirement for units with NOx post-combustion control equipment in South Coast AQMD permits, and any future units would be expected to install and maintain a temperature measuring device through the permitting process. A temperature measuring device is necessary to determine the temperature of the gas stream entering the NOx post-combustion control equipment and when the catalyst in the NOx post-combustion control equipment will effectively control NOx emissions.

Also effective January 1, 2024, paragraph (d)(9) requires the operation of NOx post-combustion control equipment during startup and shutdown events, including, but not limited to, the injection of any associated chemical reagent, water, or steam into the exhaust stream to control NOx, if the temperature of the gas to the inlet of the emission control system is greater than or equal to the minimum operating temperature, the temperature of the exhaust gas is stable, and the injection of any associated chemical reagent would not result in ammonia emissions in excess of permit conditions. This provision ensures that NOx emissions are controlled as soon as the post-combustion control is ready to effectively operate. It would not be prudent to continue injecting ammonia into the NOx post-combustion control system when it would not react to NOx even if the inlet to the NOx post-combustion control system was at or above minimum operating temperature but the electric generating unit was shutting down.

Recordkeeping (Subdivision (e))

Records assist in verifying compliance with Rule 429.2. Paragraph (e)(1) provides recordkeeping requirements for owners and operators of electric generating units. Records are required to be maintained on-site for 5 years and made available to the South Coast AQMD upon request. For data that is collected or calculated for intervals of less than 15 minutes, then that data only needs to be maintained for 48 hours. The provision in subparagraph (e)(1)(A) requires a list of scheduled startups, including date, time, duration, and reason for the scheduled startup, and any changes to the original date and time. Scheduled startups may be considered confidential data by some entities. In those cases, the facility is allowed to keep a record of the planned number of scheduled startups by January 1 of each year, but not disclose non-public information (such as specific dates and times of the scheduled startups) until after they have occurred. Subparagraph (e)(1)(B) requires the owner or operator to maintain records containing the date, time, and duration of startups and shutdowns; scheduled startups are excluded as they are already required in subparagraph (e)(1)(A). Subparagraph (e)(1)(C) requires NOx emissions data collected pursuant to Rule 1135 for each startup and shutdown. Data generated by a Data Acquisition Handling System (DAHS) that sufficiently provides any of the information required in subparagraphs (e)(1)(A) through (e)(1)(C) can be used as records.

Paragraph (e)(2) requires an owner or operator of an electric generating unit with NOx post-combustion control equipment to maintain documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment. Records are required to be on-site and made available to the South Coast AQMD upon request for compliance verification.

Exemptions (Subdivision (f))

Paragraph (g)(1) exempts Once-Through-Cooling Electric Generating Units from startup and shutdown duration limits, frequency of scheduled startups, and installation of a temperature measuring device for units that will retire the unit on or before the compliance date set forth in Table 1 of Section 2(B) of the State Water Resources Control Board's Statewide Water Quality Control Policy on the Use of Coastal Estuarine Waters for Power Plant Cooling (Once-Through-Cooling Policy) implementing Section 316(b) of the Clean Water Act. Those units are scheduled to retire in a few years; therefore it is not cost-effective to alter the equipment. Additionally, the older equipment may require additional scheduled startups to address maintenance issues. The exemption will sunset December 31, 2029 to prevent indefinite extensions of the retirement date.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

COSTS

EMISSION REDUCTIONS

COST-EFFECTIVENESS

INCREMENTAL COST-EFFECTIVENESS

SOCIOECONOMIC ASSESSMENT

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

DRAFT FINDINGS UNDER CALIFORNIA HEATH AND SAFETY CODE SECTION 40727

COMPARATIVE ANALYSIS

INTRODUCTION

Impact assessments were conducted during PAR 1135 and PR 429.2 rule developments to assess the environmental and socioeconomic implications of PAR 1135 and PR 429.2. California Health & Safety Code (H&SC) requirements for cost-effectiveness analysis, incremental cost-effectiveness analysis, and a socioeconomic assessment were evaluated during rule development of PAR 1135 and PR 429.2. Staff prepared draft findings pursuant to H&SC 40727 and an assessment of emission reductions. Staff will prepare a California Environmental Quality Act (CEQA) analysis and a comparative analysis pursuant to H&SC 40727.2 at least 30 days prior to the South Coast AQMD Governing Board Hearing on PAR 1135 and PR 429.2, which is anticipated to be heard on January 7, 2022.

COSTS

The provisions in PAR 1135 and PR 429.2 are not expected to impose any additional costs.

EMISSION REDUCTIONS

There will not be additional emission reductions from electric generating units subject to PAR 1135 and PR 429.2.

COST-EFFECTIVENESS

The H&SC Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The proposed rule does not include new BARCT requirements. Therefore, this provision does not apply to the proposed amended rule and proposed rule.

INCREMENTAL COST-EFFECTIVENESS

H&SC Section 40920.6 requires an incremental cost-effectiveness analysis for 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, CO, SOx, NOx, and their precursors. The proposed rule does not include new BARCT requirements. Therefore, this provision does not apply to the proposed rule.

SOCIOECONOMIC ASSESSMENT

PAR 1135 and PR 429.2 do not impose any additional costs to the affected facilities and do not result in any adverse socioeconomic impacts.

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, and if the proposed project is approved, the Notice of Exemption will be filed for posting with the State Clearinghouse of the Governor's Office of Planning and Research, and with the county clerks of Los Angeles, Orange, Riverside, and San Bernardino counties. In addition, the Notice of Exemption will be electronically posted on the South Coast AQMD's webpage.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Findings

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. The draft findings are as follows:

Necessity

PAR 1135 is needed to revise emission limits for diesel internal combustion engines, update provisions, and provide other clarifications. PR 429.2 is needed to establish limits on duration and frequency of startup and shutdown events for electric generating units at electricity generating facilities when units exceed the applicable emission limits in Rule 1135.

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, as well as the federal Clean Air Act.

Clarity

PAR 1135 and PR 429.2 are written or displayed so that its meaning can be easily understood by the persons directly affected by them.

Consistency

PAR 1135 and PR 429.2 are in harmony with and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

Non-Duplication

PAR 1135 and PR 429.2 will not impose the same requirements as any existing state or federal regulations. The proposed rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference

In adopting 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, and the federal Clean Air Act.

COMPARATIVE ANALYSIS

H&SC Section 40727.2 requires a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal air pollution control requirements, existing or proposed South Coast AQMD rules and regulations, and all air pollution control requirements and guidelines which are applicable to the same equipment or source type. Comparative analyses are presented below in Tables 4-1 and 4-2.

Table 4-*1: PAR 1135 Comparative Analysis*

Rule Element	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
Applicability	Boilers, internal combustion engines, and turbines located at investor-owned electric utilities, publicly owned electric utilities, and facilities with combined generation capacity of ≥ 50 MW	Gaseous and liquid fueled internal combustion engines over 50 rated brake horsepower	All NOx emitting equipment at a facility with at least 50 MW of generating capacity, in existence as of 5/11/01 and owned or operated by Southern California Edison, Los Angeles Dept. of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any their successors	All NOx emitting equipment at a facility subject to the NOx RECLAIM program (SCAQMD Reg. XX)	Electric utility steam generating units rated at 250 MMbtu/hr or greater and constructed, reconstructed, or modified after 9/18/78	Gas turbines with heat input of ≥ 10 MMBtu/hr constructed, reconstructed, or modified after 10/3/77 but before 2/18/2005	Gas turbines with heat input of ≥ 10 MMBtu/hr constructed, reconstructed, or modified on or after 2/18/2005	Power generating units operated by a utility, or any non-utility cogeneration unit that supplies at least 2/3 of their power to a utility grid
Requirements	Emission limits: • Boiler: NOx 5 ppmv @ 3% O2 • Combined Cycle Gas Turbine and Associated Duct Burner: NOx 2 ppmv @ 15% O2 • Simple Cycle Gas Turbine: NOx 2.5 ppmv @ 15% O2 • Internal Combustion Engine: NOx 45 ppmv @ 15% O2; CO 250 ppmv @ 15% O2; VOC 30 ppmv @ 15% O2; PM 0.0076 lbs/MMBtu	Existing Internal Combustion Engine: NOx 11 ppmv @ 15% O2; CO 250 ppmv @ 15% O2; VOC 30 ppmv @ 15% O2; Engines regulated under RECLAIM are not subject to the NOx limit	Submit Compliance Plan to demonstrate BARCT by 2003/2004	Provide RECLAIM Trading Credits to cover NOx emissions in a market based system	Units constructed, reconstructed, or modified prior to 7/10/97: NOx 0.2 lb/MMBtu After 7/9/97 and before 3/1/05 – constructed -1.6 lbs/MWh gross , reconstructed – – 0.15 lbs/mmbtu After 2/28/05 and before 5/4/11 constructed - !.0 lbs/MWh gross, reconstructed – 1.0 lbs/MWh gross or 0.11	NOx limit @ 15% O2: 0.0075*(14.4/Y) +F where Y = manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen	NOx limit for electric generating units (@ 15% O2): • ≤ 50 MMBtu/hr – 42 ppm when firing natural gas • 50 MMBtu/hr and ≤ 850 MMBtu/hr – 15 ppm when firing natural gas • >850 MBtu/hr – 15 ppm when firing natural gas • ≤ 50 MMBtu/hr – 96 ppm when firing other fuel • 50 MMBtu/hr and ≤ 850 MMBtu/hr – 74 ppm when firing other fuel	No limit for NOx

Rule Element	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
					lbs/mmbtu, modified – 1.4 lbs/MWh gross or 0.15 lbs/mmbtu After 5/3/11 constructed or reconstructed – 0.70 lbs/MWh gross or 0.76 lbs/ MWh net, modified – 1.1 lbs/MWh gross		• >850 MBtu/hr – 42 ppm when firing natural gas	
Reporting	Annual reporting of NOx emissions	Breakdowns, monthly portable engine logs	None	• Daily electronic reporting for major sources • Quarterly Certification of Emissions Report and Annual Permit Emissions Program for all units	Results of the performance tests Results of the CEMS performance evaluations Semiannual written reports or quarterly electronic reports of emission	Excess emissions and CEMS downtime within 30 days	Excess emissions and CEMS downtime within 30 days; annual performance testing within 60 days	40 CFR 75 requirements for quarterly reports of information and hourly data from CEMS monitors, and calibration
Monitoring	• A continuous in-stack NOx monitor	• A continuous in-stack NOx-dilutant monitor or alternative monitoring device for engines ≥ 1,000 bhp and operating more than two million bhp-hr per calendar year or for facilities with engines subject to paragraph (d)(1),	None	A continuous in-stack NOx monitor, a continuous dilutant monitor or a stack flow monitor for major sources A fuel meter For turbines, boilers and engines with SCR – ammonia	A continuous in-stack NOx-dilutant monitor	A continuous in-stack NOx-dilutant monitor	A continuous in-stack NOx-dilutant monitor, or a continuous water or steam to fuel monitor, a fuel meter, annual performance testing	A continuous in-stack NOx-dilutant monitor, or use of alternative monitoring for oil or gas fired peaking units as defined in the regulation

Rule Element	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
		having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 109 Btus per year (higher heating value) • Non-resettable totalizing time meter		injection rate and exhaust temperature For turbines and engines – shaft output				
Recordkeeping	Performance testing; emission rates; monitoring data; CEMS audits and checks maintained for five years	Operating log including total hours of operation, type and amount of fuel combusted, hours of operation since the last source test	None	• < 15-min. data = min. 48 hours; • ≥ 15-min. data = 3 years (5 years if Title V) • Maintenance & emission records, source test reports, RATA reports, audit reports and fuel meter calibration records for Annual Permit Emissions Program = 3 years (5 years if Title V)	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks maintained for three years
Fuel Restrictions	Liquid petroleum fuel limited to Force Majeure natural gas curtailment, readiness testing, and source testing	None	None	None	None	None	None	None

Table 4-2: *PR 429.2 Comparative Analysis*

Rule Element	PR 429.2	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
Applicability	Boilers, internal combustion engines, and turbines located at investor-owned electric utilities, publicly owned electric utilities, and facilities with combined generation capacity of ≥ 50 MW	Boilers, internal combustion engines, and turbines located at investor-owned electric utilities, publicly owned electric utilities, and facilities with combined generation capacity of ≥ 50 MW	Gaseous and liquid fueled internal combustion engine over 50 rated brake horsepower	All NOx emitting equipment at a facility with at least 50 MW of generating capacity, in existence as of 5/11/01, and owned or operated by Southern California Edison, Los Angeles Dept. of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any their successors	NOx RECLAIM program (SCAQMD Reg. XX)	Electric utility steam generating units at a facility rated at 250 MMBtu/hr or greater and constructed, reconstructed, or modified after 9/18/78	Gas turbines with heat input of ≥ 10 MMBtu/hr constructed, reconstructed, or modified after 10/3/77 but before 2/18/2005	Gas turbines with heat input of ≥ 10 MMBtu/hr constructed, reconstructed, or modified on or after 2/18/2005	Power generating units operated by a utility, or any non-utility cogeneration unit that supplies at least 2/3 of their power to a utility grid
Requirements	Maximum time durations for exemption from emission limits (duration limits) during startup of existing units: • Boilers: 20 hours • Combined Cycle Gas Turbine and Associated Duct Burner: 6 hours • Simple Cycle Gas Turbine: 1 hour	Meet startup, shutdown, and tuning requirements in permit; by January 1, 2024, include limits for duration, mass emissions, and number of events in permit	Startup limited to the time needed to reach sufficient operating temperature for proper operation of the control equipment not to exceed 30 minutes	None	None	Work practice requirements: • Conduct triennial or quadrennial tune-ups • Operate control devices as expeditiously as possible • Use at least one combination	None	Work practice requirements: • Minimize emissions at all times during startup, shutdown, and malfunction	None

Rule Element	PR 429.2	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
	• Internal Combustion Engine: 1 hour Shutdown duration limits for existing units: • Boilers: 12 hours • Combined Cycle Gas Turbine and Associated Duct Burner: 2 hours • Simple Cycle Gas Turbine: 45 mins • Internal Combustion Engine: 30 mins Startup duration limits for new units: • Boilers: None • Combined Cycle Gas Turbine and Associated Duct Burner: 60 mins • Simple Cycle Gas Turbine: 15 mins • Internal Combustion Engine: 30 mins Shutdown duration limits for new units: • Boilers: None • Combined Cycle Gas Turbine and Associated Duct Burner: 30 mins • Simple Cycle Gas Turbine: 10 mins • Internal					of clean fuels to maximum extent as possible for startup • Vent startup emissions to the main stack and comply with applicable emission limits (including operating the PM control device) starting at the hour after startup ends			

Rule Element	PR 429.2	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
	Combustion Engine: 30 mins Scheduled startup limits per calendar for each unit: 12 for units not required to perform distillate fuel oil readiness testing; 64 for units requiring distillate fuel oil readiness testing Work practice requirements: • Take all reasonable and prudent steps to minimize emissions during startup and shutdown • Operate NOx post-combustion control equipment if the temperature to the gas at the inlet of the NOx post-combustion control equipment is ≥ the minimum operating temperature								
Reporting	None	Annual reporting of NOx emissions	Breakdowns, monthly portable engine logs	None	• Daily electronic reporting for major sources • Quarterly Certification of Emissions Report and	• Results of the performance tests • Results of the CEMS performance evaluations	Excess emissions for all periods of unit operations, including startup, shutdown, and malfunction,	• Excess emissions and CEMS downtime within 30 days • Annual performance	40 CFR 75 requirements for quarterly reports of information and hourly data from CEMS

Rule Element	PR 429.2	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
					Annual Permit Emissions Program for all units	Semiannual written reports or quarterly electronic reports of emission	and CEMS downtime within 30 days	testing within 60 days	monitors, and calibration
Monitoring	None	• A continuous in-stack NOx monitor	• A continuous in-stack NOx monitor for engines ≥ 1,000 bhp and operating more than two million bhp-hr per calendar year or for facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 109 Btus per year (higher heating value) • Non-resettable totalizing time meter	None	A continuous in-stack NOx monitor for major sources	A continuous in-stack NOx monitor	A continuous in-stack NOx monitor	A continuous in-stack NOx monitor	A continuous in-stack NOx monitor
Recordkeeping	• List of each startup and shutdown, containing date,	Time and duration of each startup and shutdown	Operating log including total hours of operation, type	None	• < 15-min. data = min. 48 hours; • ≥ 15-min. data	Monitoring data	Monitoring data	Monitoring data	Monitoring data

Rule Element	PR 429.2	PAR 1135	Rule 1110.2	Rule 2009	RECLAIM	40 CFR Part 60 Da	40 CFR Part 60 GG	40 CFR Part 60 KKKK	40 CFR Part 72
	time, and duration; list of scheduled startups, containing date, time, duration, and reason; and emissions data shall be maintained onsite for 5 years. • Documentation from the manufacturer of the minimum operating temperature of NOx post-combustion control equipment, unless specified in the permit		and amount of fuel combusted, hours of operation since the last source test		= 3 years (5 years if Title V)				maintained for three years

APPENDIX A: COMMENTS AND RESPONSES

COMMENT LETTER 1

Vernon Public Utilities – November 2, 2021

4305 Santa Fe Avenue, Vernon, California 90058
Telephone (323) 583-8811

November 2, 2021

Attention: Charlene Nguyen
Planning, Rule Development and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765
Transmitted via Email: cnguyen@aqmd.gov

Subject: Vernon Public Utilities (VPU) Comments on South Coast Air Quality Management District (SCAQMD) Proposed Amended Rule 1135

Dear Ms. Nguyen,

Vernon Public Utilities (VPU, Facility ID 014502) is pleased to submit these Comments setting forth VPU's concerns regarding South Coast Air Quality Management District's (SCAQMD) Proposed Amended Rule (PAR) 1135[1]. VPU has provided a brief history of VPU's operations and prior discussions with SCAQMD staff for informational purposes, as well as two alternative solutions for SCAQMD's consideration.

History/Background

VPU owns eight process units subject to the REgional CLean Air Incentives Market (RECLAIM) Program. Currently operational sources include two natural gas-fired peaking turbines (Units D1 and D2) and one diesel-fired emergency generator (Unit D25). VPU has five additional diesel-fired emergency generators (Units D3, D4, D5, D6, and D7) which are non-operational with fuel lines disconnected.

As a part of the SCAQMD's transition from the market-based RECLAIM Program to a command-and-control regulatory structure, updates to existing rules and new rules are being developed, some of which will affect VPU. For example, following sunset of the RECLAIM Program, VPU's Units D1 and D2

[1] References to PAR 1135 reflect the version dated October 22, 2021.

Exclusively Industrial

will be newly subject to *SCAQMD Rule 1135: Emissions of Oxides of Nitrogen (NOx) from Electricity Generating Facilities*. Rule 1135 was last amended November 2, 2018 to incorporate facilities exiting the RECLAIM Program and implement Best Available Retrofit Control Technology (BARCT) for NOx emissions from gas turbines, boilers, and select diesel internal combustion engines. SCAQMD is currently proposing additional amendments to Rule 1135 for consistency with policy changes implemented after November 2, 2018, such as requirements for Continuous Emission Monitoring Systems (CEMS).

SCAQMD has provided two options for Facilities transitioning from RECLAIM to meet the compliance requirements of Rule 1135: (1) meet the hourly NOx BARCT emission limits, as demonstrated through a CEMS; or (2) qualify for one of the exemptions provided in Rule 1135. Due to the excessive cost associated with implementing BARCT and CEMS, VPU instead plans to limit operation of Units D1 and D2 such that both units qualify for Rule 1135's Low Use Exemption and Backup Unit Exemption, as described below. VPU's Post-RECLAIM plans for its remaining units are not addressed in these Comments, as they will continue to not be subject to Rule 1135.

Previous Discussions with SCAQMD Staff

On June 22, 2021, SCAQMD's Planning, Rule Development and Area Sources staff met with VPU personnel at VPU's Station A. During this meeting, VPU personnel provided insight into the day-to-day operations of Station A, including a tour of the electricity generating units, and received a brief overview of PAR 1135 from SCAQMD staff. The tone set during this meeting was one of collaboration, in which it appeared SCAQMD wanted to (1) understand VPU's operations; and (2) work with VPU regarding the treatment of generators with minimal impact in the SCAQMD's PAR 1135.

Requiring VPU to install CEMS and/or comply with BARCT would impose additional and excessive costs to the facility.

Rule 1135 Exemptions

A discussion of the two Rule 1135 exemptions applicable to VPU's Units D1 and D2 is provided below.

Rule 1135 Low Use Exemption

To qualify for the currently-effective Low Use exemption of Rule 1135, each peaking turbine must limit operation based on a calculated annual capacity factor.[2] The Low Use exemption criteria for each of VPU's gas turbines are as follows (PAR 1135[g][4][A]):

- Maintains an annual capacity factor of less than ten percent averaged over three consecutive calendar years;
- Maintains an annual capacity factor of less than twenty-five percent each calendar year; and

[2] The annual capacity factor is the ratio between the actual measured heat input during a calendar year and the potential heat input had the unit operated continuously at the permitted heat input rating.

- Retains the NOx and ammonia limits, averaging times, startup, shutdown, and, if applicable, tuning requirements in the facility's current Title V Permit.[3]

In addition to the Low use Exemption criteria described above, each of VPU's peaking turbines must continue to comply with its current permitted emission limits to qualify for the Low Use exemption. Section D of VPU's Title V Permit establishes the following NOx emission limits for the peaking turbines: 91.09 pounds per million standard cubic feet (lb/MMscf) for natural gas and 20.06 pounds per thousand gallons (lb/1,000 gal) for fuel oil. Note that VPU's Title V Permit does not contain ammonia emission limits or mass- or concentration-based NOx emission limits. Per correspondence with SCAQMD's Planning and Rules Manager M. Morris, <u>facilities will not be required to add emission limits to their existing permits</u> in order to qualify for the Low Use exemption.[4]

PAR 1135 Backup Unit Exemption

The most recent version of PAR 1135 (October 22, 2021) includes a new means for exemption, the "Backup Unit Exemption". Under PAR 1135, Units qualifying as "Backup Units" would be exempt from the Rule 218 CEMS requirements used to demonstrate compliance with NOx emission limits until July 1, 2026. VPU's peaking units D1 and D2 would meet the new definition of a "Backup Unit" (PAR 1135[c][2]):

> "BACKUP UNIT means any NOx emitting turbine which is used intermittently to produce energy on a demand basis, does not operate more than 1,300 hours per year, is not subject to 40 [Code of Federal Regulations] CFR Part 72, and was a NOx process unit prior to the facility becoming a former RECLAIM NOx facility."

For a Backup Unit to be exempt from CEMS installation until July 1, 2026 (PAR 1135[e][3]), it must comply with annual NOx source testing[5], as well as continued implementation of certain requirements (i.e., quarterly reporting of NOx emissions, submittal of source test protocols, and use of a totalizing fuel meter). Additionally, to qualify for the exemption, operation of a Backup Unit must be limited by permit condition to 1,300 hours per year.[6]

<u>PAR 1135 As Currently Drafted Appears to Contain Contradicting Criteria for Units that Qualify as Both "Low Use" and "Backup Unit" Exempt</u>

Per PAR 1135(g)(4)(A), equipment that qualifies as Low Use "*shall not be subject to emission limits specified under paragraph (d)(1)* [Rule 1135's NOx emission limits] *for that gas turbine*...[and] *Retains the NOx and ammonia limits, averaging times, and startup, shutdown, and, if applicable, tuning requirements specified on the Permit to Operate as of November 2, 2018.*" As previously discussed, VPU proposes to operate Units D1 and D2 in accordance with the Low Use exemption such that their 1-1

[3] Note that PAR 1135 defines the "current Title V Permit" as the Permit to Operate in effect as of November 2, 2018.
[4] September 25, 2019 phone communication between SCAQMD's M. Morris and Jacobs' E. Schwing
[5] Per PAR 1135(e)(3)(B), annual source testing must demonstrate compliance with the NOx emission limits of this rule.
[6] Permit applications to limit annual hours of operation must be submitted within 6 months of becoming a former RECLAIM facility (PAR 1135[e][3][I]).

City of Vernon, 4305 Santa Fe Avenue, Vernon, California 90058 – Telephone (323) 583-8811

operation would be subject to the Low Use exemption criteria. These criteria currently include the NOx emission limits of their current permit, which limits are not monitored using CEMS.

Also as stated above, SCAQMD's latest proposed amendments to Rule 1135 consider RECLAIM NOx process units (including NOx peaking units like VPU's Units D1 and D2) to be Backup Units. This new exemption delays the installation of CEMS, but requires annual source testing until July 1, 2026 (PAR 1135[e][3]). However, as written, the rule requires source testing to demonstrate compliance with Rule 1135's NOx emission limits (2.5 parts per million by volume [ppmv] for simple cycle turbines[7]).

VPU's expectation was that Units D1 and D2 would be exempt from installing CEMS because they would meet the low use exemption criteria of PAR 1135(g)(4)(A) and would, therefore, not be subject to the NOx emission limits specified in PAR 1135(d)(1). However, with the addition of their classification as Backup Units, these units would also be required to conduct annual source testing to demonstrate compliance with Rule 1135's NOx emission limits or install CEMS prior to July 1, 2026. As currently permitted, VPU's Units D1 and D2 do not meet Rule 1135's NOx emission limits because they are not equipped with selective catalytic reduction (SCR). For this reason alone, VPU has always intended to apply for Rule 1135's Low Use Exemption for its Units D1 and D2.

As currently drafted, it is unclear how a unit eligible for both the Low Use Exemption and the Backup Unit Exemption would demonstrate compliance with the Backup Unit Exemption. Despite eligibility for the Low Use Exemption, as currently drafted PAR 1135 appears to require VPU to either (1) install CEMS for its Units D1 and D2 prior to July 1, 2026 (to demonstrate compliance with emission limits to which the units are not subject) (PAR 1135[e][3][2]); or (2) install an SCR to reduce emissions and perform annual source testing (again, to demonstrate compliance with emission limits to which the units are not subject) (PAR 1135[e][3][B]). Both options would be cost prohibitive and likely result in the near-term, permanent shutdown of VPU's Units D1 and D2, which would be in direct conflict to the goals presented in SCAQMD's October 27, 2021 Public Workshop Presentation. In that Presentation, SCAQMD stated: "PAR 1135 and [Proposed Rule] PR 429.2 do not impose additional costs to the affected facilities." Since VPU does not believe SCAQMD's intent is to force facility shutdowns, VPU is hopeful that its concerns with PAR 1135 can be resolved. 1-1 cont.

VPU's Two Alternative Proposed Solutions

As explained above, PAR 1135 appears to contain contradicting exemptions regarding CEMS and NOx emission limit requirements. To eliminate the apparent contradiction between the exemptions, VPU recommends SCAQMD take one of the following two approaches:

- Revise PAR 1135(g)(4)(A) to clarify that Units qualifying for the Low Use Exemption shall neither be subject to the Rule 1135 NOx emission limits of PAR 1135(d)(1) nor the requirement to install CEMS per PAR 1135(e)(2), without the need for annual source testing, or

- Revise PAR 1135(e)(3)(B) to require annual source testing to demonstrate compliance with the NOx emission limits of the Facility's Permit to Operate as of November 2, 2018, if applicable, instead of the NOx emission limits set forth in Rule 1135.

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[77] PAR 1135(d)(1), Table 1.

November 2, 2021 Page 5

We appreciate your consideration of these matters and welcome your feedback. If additional information is desired, please contact Lisa Umeda (lumeda@ci.vernon.ca.us) or Elyse Engel (elyse.engel@jacobs.com).

Sincerely,

Abraham Alemu

Abraham Alemu
General Manager of Vernon Public Utilities

Copies to: Uyen-Uyen Vo/SCAQMD
Michael Morris/SCAQMD
Lisa Umeda/VPU
Elyse Engel/Jacobs
Andrea White/Jacobs

City of Vernon, 4305 Santa Fe Avenue, Vernon, California 90058 – Telephone (323) 583-8811

Staff Response to Comment Letter 1

Response to Comment 1-1:

Staff has revised the rule language in subparagraph (e)(3)(B) to resolve the contradicting exemptions. Backup units will be required to conduct annual source tests to demonstrate compliance with their permit limits.

COMMENT LETTER 2

Community Environmental Services – November 10, 2021

Charlene Nguyen

From:	Mark Abramowitz <marka@enviropolicy.com>
Sent:	Wednesday, November 10, 2021 9:56 AM
To:	Michael Morris; Uyen-Uyen Vo; Charlene Nguyen
Cc:	Susan Nakamura; Sarah Rees; Wayne Nastri; bbenoit@cityofwildomar.org; Sheila Kuehl; Vanessa Delgado; Veronica Padilla-Campos; Rex Richardson; Janice Rutherford (GBM); Ruthanne Taylor Berger (Ben); Dan York (Ben); Thomas Gross; Tricia Almiron; Sandra Hernandez (Del); Teresa Acosta (Del); Alisa Cota; Cristian Riesgo (Del); Loraine Lundquist; Amy Wong; Matthew Hamlett; Mark Taylor (Rut); Debra Mendelsohn
Subject:	Proposed Amended Rule 1135

SCAQMD staff,

Thank you for the opportunity to comment on the proposed changes to rule 1135, as presented at the Public Workshop.

CES is concerned about the lack of analysis, as well as the substance of the proposed substantive changes that reduce the stringency of the rule. A portion of the proposed changes are designed to address the plans of Southern California Edison to install brand new prime power Diesel engines on Santa Catalina Island, engines which cannot comply with the existing requirements of rule 1135. SCE chose this path after engaging NREL to evaluate several options, none of which evaluate feasible options to install zero emission fuel cells. The proposed changes weaken and reduce the stringency of Rule 1135 without an analysis evaluating the ability to use zero emission technology, or requiring BARCT. The proposed changes to the proposed rule appear to be contrary to state law and a myriad of District environmental justice and other policies.

California Health and Safety Code section 40440 requires the District to adopt rules and regulations that reflect Best Available Retrofit Control Technology (BARCT). The proposed amendments fail to reflect BARCT, as there exist zero emission technologies that can perform the same functions for prime electricity production as the very Diesel engines that SCE wishes to install. Unfortunately, the District failed to perform any BARCT or other analysis of the possibility of using zero emission technologies, which are now commercially available. 2-1

Commercially available fuel cells meet all the requirements for both Reasonably Available Control Technology and Best Available Retrofit Control Technology. In this case, since the changes will only apply to the SCE engines on Santa Catalina island, and will be replaced and not retrofitted, the rule changes should also be equivalent to Lowest Achievable Emission Rate (LAER), requirements that a fuel cell will also meet. 2-2

Adopted in September, 2011, the District has an energy policy with a number of policies that the proposed amendments appear to violate. For example, Policy 7 requires any new/repowered in-Basin fossil-fueled generation power plant to incorporate BACT/LAER as required by South Coast AQMD rules, considering energy efficiency for the application. 2-3

1

The proposed amendments appear to violate both the spirit and letter of the District's energy policy by amending Rule 1135 to conform to SCE's wish to install Diesel engines, engines which do not reflect BACT or LAER for generating power.

The proposed amendments would also conflict with the District's aging Clean Fuels Policy, which require the use of clean fuels as part of BACT or LAER. 2-3 cont.

The proposed amendments also are contrary to the District's 10 original environmental justice initiatives. Number 7 calls for the District "(c)reate incentives to clean-up or remove diesel engines in the basin…". The proposed amendments actually create an *incentive* for SCE by weakening Rule 1135. Without the proposed amendments, SCE could not comply with Rule 1135, and be forced to evaluate cleaner options, with cleaner fuels.

Further, the proposed amendments would be inconsistent with the intent of AB 1807 (Tanner), designed to identify and reduce emissions of toxic air contaminants. Diesel particulate matter has already been identified by the California Air Resources Board as a toxic air contamination, and the proposed amendments would facilitate their continued emission. 2-4

District staff has represented to the public on numerous occasions that it intends to include in the next AQMP a proposed measure to replace emergency backup diesel generators with zero emission technologies like batteries or fuel cells. This makes it is hard to understand why the District would propose to substantively *weakening* existing rule requirements for *prime* Diesel engines, rather than ensure that these engines are replaced by zero emission alternatives. Surely prime Diesel engine emissions will be more cost effective to reduce than emergency backup engines. And surely **all** of those emission reductions are needed to meet ambient air quality standards as soon as practicable. Yet the District offers no explanation for bypassing these potential emission reductions for these high-emitting units, or even analyzing the potential for alternatives. 2-5

We urge the District to re-evaluate the proposed amendments, perform a proper analysis, and propose amendments that would require NOx emission limits of zero, reflecting the current state of power generation technology.

- Mark Abramowitz
President
Community Environmental Services
18847 Via Sereno
Yorba Linda, CA 92886
(714) 936-6338
Marka@enviropolicy.com

Sent from my Fuel Cell powered iPhone

Staff Response to Comment Letter 2

Response to Comment 2-1:

A BARCT assessment was conducted for each class and category of equipment as part of the 2018 amendment to Rule 1135. Based on California Health and Safety Code Section 40406, "best available retrofit control technology" means an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source. Rule 1135 included two compliance paths for diesel internal combustion engines at Santa Catalina Island: 1) Meet a NOx emission standard of 45 ppm by January 1, 2024; or 2) Meet a mass NOx emission cap of 13 tons per year by January 1, 2026. Both options had a three-year time extension, provided certain conditions were met.

To achieve the 13 tons per year mass emission cap, it was assumed that a zero or near-zero emission technology would be used, possibly with diesel engine replacements. The longer timeframe for the mass emission cap option was provided since two potential technologies were being discussed, including solar and undersea cables, and both technologies would require further time to develop considering permitting, space constraints, and lack of infrastructure on Catalina Island. To ensure the technology is "achievable" a longer timeframe was allowed under Rule 1135. Even though fuel cells were not specifically evaluated, an operator is not precluded from using fuel cells or any other technology to achieve the 13 tons per year mass emission cap by 2026. Since the 2018 assessment, near-zero and zero-emission technologies have progressed. Staff is including a Resolution to conduct an updated BARCT assessment as soon as practicable for the electric generating units on Catalina Island and to begin the rule development process to amend to Rule 1135 beginning February 2022 to reflect the revised BARCT assessment.

Response to Comment 2-2:

Any new equipment is subject to BACT requirements and new equipment located at major sources is subject to LAER. South Coast AQMD is technology neutral with respect to what specific equipment is installed to meet rule requirements as well as BACT and LAER requirements, if applicable.

Response to Comment 2-3:

The BACT and LAER requirements assume that natural gas is available in sufficient quantities to operate the equipment. Similarly, Clean Fuels Policy assumes that the cleaner fuels are available in sufficient quantities. In the case of engines on Catalina Island, natural gas was determined to be unavailable in sufficient quantities to provide power for Catalina Island. SCE, in conjunction with U.S. EPA and the National Renewable Energy Laboratory, conducted a feasibility study and concluded that more land would be necessary to store propane as an alternative to natural gas[4]. The Santa Catalina Island Conservancy would need to authorize the additional land for fuel storage. The Conservancy set aside 88 percent of the island for preservation of the natural character

[4] "Santa Catalina Island Repower Feasibility Study," authored by consulting group NV5 in partnership with the National Renewable Energy Laboratory and U.S. Environmental Protection Agency. https://www.sce.com/about-us/reliability/upgrading-transmission/catalina-repower

of the island and generally ensures that the island remain in its present natural state. As part of the updated BARCT assessment, staff will evaluate if challenges with fuel storage can be resolved.

The proposed amendment to average NOx emissions over a three-hour period is included to avoid unnecessary startups and shutdowns that would create additional emissions. Without the amendment, the engines would be shut down more often to address transitory spikes leading to higher emissions when the engines are restarted.

Response to Comment 2-4:

The proposed amendments do not alter the diesel particulate emission limit. The replacement engines are required to meet a particulate matter standard of 0.0076 lbs/MMbtu. This limit is a significant decrease from the older existing engines which do not have any particulate control.

Response to Comment 2-5:

The proposed amendment to extend the averaging time does not weaken the existing rule requirements. The proposed amendment to average NOx emissions over a three-hour period is included to avoid unnecessary startups and shutdowns that would create additional emissions. Without the amendment, the engines would be shut down more often to address transitory spikes leading to higher emissions when the engines are restarted. Staff is including a Resolution to conduct an updated BARCT assessment as soon as practicable for the electric generating units on Catalina Island and to begin the rule development process to amend Rule 1135 in February 2022 to reflect the revised BARCT assessment.

COMMENT LETTER 3

Southern California Edison – November 10, 2021

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

P.O. Box 5085 Rosemead, CA 91770

November 10, 2021

Charlene Nguyen
Planning, Rule Development and Area Sources
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765
Email: cnguyen@aqmd.gov

SUBJECT: Proposed Amended Rule 1135 - Emissions of Oxides of Nitrogen from Electricity Generating Facilities and Proposed Rule 429.2 - Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities

Dear Ms. Nguyen:

Southern California Edison (SCE) appreciates the opportunity to comment on the South Coast Air Quality Management District's (SCAQMD) Proposed Amended Rule (PAR) 1135 and Proposed Rule (PR) 429.2. SCE remains committed to working with the SCAQMD to comply with the rules.

SCE supports the provisions of PAR 1135 and PR 429.2 relating to our combined-cycle gas turbine facility (Mountainview Generating Station) and four simple-cycle gas turbine facilities (Barre, Center, Grapeland, and Mira Loma Peakers). SCE also supports many proposed requirements regarding non-emergency diesel internal combustion engines and appreciates SCAQMD for recognizing the unique operation and challenges at our Pebbly Beach Generating Station ("PBGS") on Santa Catalina Island ("Catalina" or "the Island"). Nevertheless, SCE has a few remaining concerns about the effect of the proposed rules on our Catalina facility. Our suggested rule revisions presented below will take the form of additions shown in **bold underline** and deletions in ~~strikethrough~~.

PAR 1135

A. The definition of "Electricity Generating Facility" is ambiguous and could be misinterpreted to include all facilities owned and operated by an investor-owned utility such as SCE or a public utility. 3-1

The current and proposed amended definitions could subject our office buildings, service centers, garages, and substations to Rule 1135, which we believe is not the SCAQMD's intent. SCE requests the following revisions to the definition in subparagraph (c)(9):

> ELECTRICITY GENERATING FACILITY means a facility that is owned or operated by an investor-owned electric utility **<u>or a publicly owned electric utility and includes one or more electric generating units</u>**; ~~is owned or operated by a publicly owned electric utility~~; or has electric generating units with a combined generation capacity of 50 megawatts or more of electrical power for distribution in the state or local electrical grid system. 3-1 cont.

and the related definition of "Electric Generating Unit" in subparagraph (c)(8):

> ELECTRIC GENERATING UNIT means a boiler that generates electric power, gas turbine that generates electric power with the exception of cogeneration turbines, or **a** diesel internal combustion engine that generates electric power and is located on Santa Catalina Island with the exception of emergency internal combustion engines **<u>and portable engines registered under the Statewide Portable Equipment Registration Program (PERP)</u>**. 3-2

SCE constructs and maintains power distribution lines throughout the island and uses portable equipment and generators as allowed under the state's Portable Equipment Registration Program (PERP) in the field, staging areas, laydown yards, and other locations throughout the island. By adding these clarifications, all six SCE electricity generating facilities will remain subject to Rule 1135, but other non-power producing facilities such as offices, substations, warehouses, laydown yards, and service centers would be excluded.

B. Emissions data averaging methodology should align with Rule 218.3 requirements.

SCE appreciates SCAQMD's consideration in proposing an oxides of nitrogen (NOx) emissions limit that both meets Best Available Control Technology (BACT) requirements and addresses SCE's operational challenges at our Catalina facility. SCE supports the proposed limits with a few minor modifications to the Table 2 footnotes under subparagraph (d)(2) that would ensure emissions monitoring, recordkeeping, and reporting requirements are consistent with Rules 218, 218.1, 218.2, and 218.3.

When the existing diesel engines have been replaced, PBGS will become a Former RECLAIM NOx Facility[1] and will be subject to Rule 1135 (e)(2), which requires the facility to meet emissions monitoring, recordkeeping, and reporting requirements in accordance with Rules 218, 218.1, 218.2, and 218.3. As a Former RECLAIM NOx Facility, PBGS will continue to monitor NOx emissions from its non-emergency engines with a Continuous Emissions Monitoring System (CEMS). While Rule

[1] PAR Rule 1135 (C)(14) defines "Former RECLAIM NOx Facility" as "a facility or any of its successors that was in the NOx Regional Clean Air Incentives Market (RECLAIM) as of January 5, 2018, as established in Regulation XX – Regional Clean Air Incentive Market (RECLAIM), that has received a final determination notification, and is no longer in the NOx RECLAIM program.

1135 (e)(2) generally provides appropriate cross-references to the Rule 218 series, SCE believes the Table 2 footnotes under subparagraph (d)(2) must be revised to ensure consistency.

As previously communicated to SCAQMD, SCE plans to replace the existing engines with United Stated Environmental Protection Agency (US EPA) Tier 4 Final certified diesel generator sets. The Tier 4 Final generator sets will achieve significant NOx emissions reductions and are considered BACT. As discussed in SCAQMD's PAR 1135 and PR 429.2 Preliminary Draft Staff Report, the NOx concentration limit in Table 2 under subparagraph (d)(2) was derived from the Tier 4 Final emission standard of 0.67 g/kWh (gram per kilowatt-hour) or 0.50 g/bhp-hr (gram per brake horsepower hour) with an assumed engine efficiency of 40 percent. SCE supports SCAQMD's approach to demonstrate compliance in terms of concentration limits. While the emissions rates in g/kWh or g/bhp-hr cannot be directly converted to an equivalent NOx concentration in ppmv (part per million volume), SCE believes that the concentration limit must reflect the emissions performance capacity of the Tier 4 Final certification level. SCE's suggested changes to the Table 2 footnotes are discussed below.

<u>Fuel-Weighted Average</u>

SCE appreciates SCAQMD including the three-hour rolling average at 45 ppmv at 15% O_2 for the diesel engines to address temporary NOx emission spikes. However, we believe that a fuel-weighted average is neither necessary nor appropriate to monitor and demonstrate compliance. In a particular three-hour period, depending on load levels and fuel use, the fuel-weighted average approach could result in an emissions concentration limit more stringent than the Tier 4 Final certification level. It is more appropriate to express the 45 ppmv NOx limit as a "straight" average concentration, i.e., as measured and correct to 15% O_2, in accordance with Rule 218.3.

Additionally, to maintain compliance and low emissions, SCE operators continuously monitor CEMS average emissions data in real time, compare that data to our permit limits, and proactively adjust various operating parameters as needed (e.g., operating loads, fuel/air ratio, and urea injection rates). Due to the nature of a fuel-weighted average calculation, the current CEMS would not allow the operators to monitor three-hour average emissions in real time to compare against the 45 ppmv permit limit. Thus, the operators would not be able to quickly address emissions fluctuations and avoid deviations from permitted limits. 3-3

To maintain accuracy and compliance and consistency with Rule 218.3 and the Tier 4 Final emissions performance standards, the NOx emissions limit should be expressed as a straight average concentration instead of as a fuel-weighted average.

Rolling Average

The term "Rolling Average" in Footnote 1 needs a cross-reference to Rule 218.3(i)(4)(C), which specifically addresses averaging times greater than one hour and refers to subsection (i)(4)(A) for individual hour requirements, as follows:

> For continuous monitoring systems used to demonstrate compliance for an interval greater than one-hour, emission data may be averaged for the required interval utilizing hourly averages computed in accordance with subparagraph (i)(4)(A). 3-4

To maintain consistency with Rule 218.3 and reduce ambiguity regarding to the NOx concentration limit under subparagraph (d)(2)(B), SCE requests that SCAQMD revise Footnote 1 as follows:

> [1] – Corrected to 15% oxygen on a dry basis **~~and fuel weighted averaged~~** over a three-hour rolling average **utilizing hourly averages computed in accordance with Rule 218.3 (i)(4)(A) and (C)**.

Additionally, SCE requests that Footnote 4 be revised to include "tuning" to be consistent with the compliance requirements for gas turbines and boilers in Footnote 1, as follows:

> [4] – The NOx, carbon monoxide, and volatile organic compounds emissions limits in Table 2 shall not apply during startup and shutdown, pursuant to Rule 429.2, **and tuning**. 3-5

C. Clarification of the time extension request administrative procedure is needed.

SCE appreciates the proposed revisions to the time extension criteria for our Catalina facility. We recognize the urgency in reducing NOx emissions as early as January 1, 2023. Should a time extension be needed due to challenges or delays outside of the facility's control, SCE requests further clarification on the timeline and procedure to implement the time extensions in subparagraph (d)(3)(C) and mitigation fee in subparagraph (d)(3)(F). 3-6

PR 429.2

A. The number of scheduled startups should be increased to allow scheduled startups during quarterly source tests and additional planned outages.

PR 429.2 defines the term "scheduled startup" in subparagraph (c)(8) as follows: 3-7

> SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year. A scheduled startup does not include a startup to meet energy demand, perform unplanned maintenance, or correct equipment failure, breakdown, or malfunction

SCE recommends that ten (10) scheduled startups be allowed for each calendar year to ensure consistency in compliance requirements between Rules 429.2 and 1135 and to address operational needs for planned outages.

PR 429.2 (d)(5) states that on and after January 1, 2024, an owner or operator of an electric generating unit shall not exceed two scheduled startups per calendar year for each generating unit.

However, PAR 1135 (e)(6) requires quarterly (i.e., four) source tests during the first 12 months of operation to demonstrate compliance with a unit's ammonia emissions limit. Each source test is considered a "scheduled startup" because it requires shutting down the unit, setting up testing equipment, and restarting the unit to complete the test as currently performed at the Catalina facility on a quarterly basis. 3-7 cont.

SCE therefore requests an increase in the number of scheduled startups allowed in PR 429.2(d)(5) from two (2) to four (4) at a minimum. SCE also urges the District to consider more than four (4) startups to account for any additional planned outages that might be needed in a calendar year. SCE believes ten (10) scheduled startups would be reasonable.

Conclusion

Thank you for your consideration of SCE's comments on the proposed rules. We share SCAQMD's goals to reduce NOx emissions expeditiously. SCE appreciates the time and effort the District staff has invested in addressing many complex energy and air quality challenges on Santa Catalina Island. We look forward to continuing to work with you and your staff on this process. If you have any questions or would like to discuss these issues, please contact Joy Brooks, Senior Air Quality Manager at (626) 302-8850 or joy.s.brooks@sce.com.

Sincerely,

DocuSigned by:
Rosalie Barcinas
06DD81A11EA7451...

Rosalie Barcinas,
Director of Catalina Operations & Strategy, Generation

CC: Susan Nakamura, SCAQMD
Michael Morris, SCAQMD
Uyen-Uyen Vo, SCAQMD
Jim Buerkle, SCE
Kenneth Borngrebe, SCE
Dawn Anaiscourt, SCE

Staff Response to Comment Letter 3

Response to Comment 3-1:

Staff has revised the rule language in PAR 1135 paragraph (c)(9) to clarify that the "Electricity Generating Facility" is defined as investor-owned electric utilities and publicly owned electric utilities with electric generating units.

Response to Comment 3-2:

Staff has revised the rule language in PAR 1135 paragraph (c)(8) to exclude portable engines registered under the CARB Statewide Portable Equipment Registration Program (PERP) from the definition of "Electric Generating Unit."

Response to Comment 3-3:

Staff has revised the rule language in PAR 1135 Table 2 Footnote 1 to be a straight three-hour rolling average instead of a three-hour fuel-weighted average to decrease the complexity of determining compliance and for consistency with other South Coast AQMD rules which require a straight average.

Response to Comment 3-4:

Staff revised the rule language in PAR 1135 Table 2 Footnote 1 to include a reference for the rolling average to be calculated as specified in Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications (Rule 218.3). The specific references to subparagraphs (i)(4)(A) and (i)(4)(C) are not included in the rule language. If Rule 218.3 gets amended in the future and the references to the subparagraphs change, then the reference in Rule 1135 would become obsolete. However, staff makes this clarification in Chapter 2 of this Staff Report.

Response to Comment 3-5:

Staff revised rule language in PAR 1135 subparagraph (d)(5) to include an exemption from Rule 1135 emission limits during tuning if the unit's Permit to Operate includes limitations for duration and number of tunings.

Response to Comment 3-6:

Staff will include a Resolution to conduct a BARCT assessment for the electric generating units on Catalina Island and to begin the rule development process in February 2022 to amend Rule 1135 in February 2022 to reflect the revised BARCT assessment. That assessment will include the criteria and requisites for a further extension due to unforeseen circumstances. Additionally, relief is available through the Hearing Board process if such a situation arises.

Response to Comment 3-7:

Staff revised the rule language in PR 429.2 paragraph (d)(5) from two to twelve scheduled startups per calendar year for electric generating units that are not required to perform distillate fuel oil readiness testing based on comments from several stakeholders and to anticipate all scheduled startups.

COMMENT LETTER 4

Los Angeles Department of Water and Power – November 15, 2021

LA DWP Los Angeles Department of Water & Power

BUILDING A STRONGER L.A.

November 15, 2021

Mr. Michael Morris
Planning and Rules Manager
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Dear Mr. Morris:

Subject: Los Angeles Department of Water and Power's (LADWP) Comments on Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities and Proposed Rule 429.2– Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities

LADWP appreciates the opportunity to provide comments on the Proposed Amended Rule (PAR) 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities and Proposed Rule (PR) 429.2– Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities. LADWP remains committed to working with the South Coast Air Quality Management District (SCAQMD) during this rulemaking process and looks forward to refining the proposed language in ensuring a successful implementation of the proposed rules.

LADWP is the largest municipality in the nation. A vertical integrated utility, LADWP is unique in that it owns and operates its own generation, transmission, and distribution systems. For this reason, LADWP does not rely on the energy market or other transmission system operators as a primary means to meet its power needs. LADWP is required by its City Charter to provide reliable and affordable power to the City of Los Angeles. Grid reliability and being able to operate its generating stations at all times is a regulatory certainty that LADWP must be allowed in order to meet the City Charter mandate.

In this letter, LADWP will be providing comments on draft language that was presented during the PAR 1135 and PR 429.2 Working Group meeting held on October 27, 2021.

111 N. Hope Street, Los Angeles, California 90012-2607 Mailing Address: PO Box 51111, Los Angeles, CA 90051-5700
Telephone (213) 367-4211 ladwp.com

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November 15, 2021

In response to SCAQMD's request for stakeholder input, LADWP respectfully submits the following comments on the draft rule language.

Comments on Proposed Amended Rule 1135 –
Continuous Emission Monitoring Performance Specifications

1. Section (d)(5) – Change of Permit Conditions

"On or before July 1, 2022, the owner or operator of an electricity generating facility shall submit an application for a change of permit conditions to reconcile their permit(s) with Rule 1135."

Comment: LADWP seeks clarification on whether the permit changes required by Rule 1135 involve adding a blanket permit provision reflecting the applicability of Rule 1135 to the permit or if each individual unit permit condition must be updated or revised to reflect the new provisions under the rule. Rule 1135 is projected to be amended by January 7, 2022, and LADWP will have to apply for permit modifications to reconcile permits with this rule. To allow for sufficient time to consolidate all permit changes and comply with the regulation, LADWP suggests that the permit application due date be extended one year after the date of Rule 1135 amendment adoption. LADWP requests that the permit application due date be extended from July 1, 2022 to January 7, 2023. 4-1

LADWP also seeks confirmation that when the permit is revised, the new permit limits will be effective once the units exit RECLAIM and not upon adoption of the rule or when the revised permit is issued. LADWP would also like clarification on whether compliance with Rule 1135's specified concentration limits is expected by December 31, 2023 if the RECLAIM exit will potentially be delayed to 2024. LADWP requests that the facility permits provide clarity on the compliance obligations for RECLAIM regulations and Rule 1135 in the event that the approved RECLAIM exit is delayed past 2023. 4-2

2. Section (f)(2) – Fuel Oil Readiness Testing

Comment: LADWP uses diesel fuel as a backup fuel. LADWP requests SCAQMD to change all references to "fuel oil" to "distillate fuel oil" in this section to capture both diesel and fuel oils. 4-3

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Comments on Proposed Rule 429.2 –
Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities

1. Section (c)(8) – Scheduled Startup Definition

"SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year. A scheduled startup does not include a startup to meet energy demand, perform unplanned maintenance, or correct equipment failure, breakdown, or malfunction."

Comment 1: LADWP seeks clarification as to whether startups due to periodic source testing, diesel readiness testing, and other required regulatory testing are considered scheduled startups. If these events are considered scheduled startups, the proposed annual limit of two specified in Section (d)(5) is not sufficient to meet permit conditions and maintain electrical system reliability, given the frequency of startups due to these required tests. Table A below shows the annual total of source tests and allowed diesel readiness testing as required by the Title V Operating Permit (Permit): 4-4

Table A – Number of Periodic Testing Per Unit Type Per Year

Unit Type	Source Testing*	Diesel Readiness Testing	Annual Total
Boiler	3	0	3
Simple Cycle	4-10	12	16-22
Combined Cycle	7-12	52	59-64

*Required source tests include RATA (up to two a year), Ammonia Slip (up to 4 a year), CO, NOx performance, PM (3 per year at full load, full load with ducts, minimum load), Trienneial (PM2.5, SOx and VOC).

In addition, LADWP generating units are subject to periodic Western Electricity Coordinating Council (WECC) testing needed to ensure system reliability. LADWP is requesting SCAQMD to exclude source tests, diesel readiness testing, and system reliability testing from the "Scheduled Startup" definition or increase the number of allowed scheduled startups in Section (d)(5) to accommodate scheduled testing listed in the table above.

Comment 2: SCAQMD's proposed requirement for facilities to specify outage (or scheduled startup) dates at the beginning of the year would be difficult for LADWP to comply with. LADWP, as its own balancing authority, maintains the balance of power supply and demand by managing both the generation and transmission within its 4-5 service territory. As a transmission provider, LADWP is subject to the Federal Energy Regulatory Commission's (FERC) Standards of Conduct (specifically the No Conduit Rule) that prohibit LADWP from sharing and disclosing non-public transmission information prior to it becoming public.

Similarly, non-public generation information such as maintenance outage and restart schedules are considered market-sensitive information that cannot be shared beyond the intended use and is therefore not intended for publication. Sharing this information with individuals outside of the designated groups within LADWP would require Non-disclosure Agreements (NDAs). 4-5 cont.

<u>Comment 3</u>: In the Permit, startups are categorized "cold" and "non-cold" for combined cycle units and simply "startup" for simple cycle units. Each startup category is subject to the time, emission concentration, and mass limits specified in the Permit whether it be scheduled startup or demand response startup. The Permit also limits the number of allowed startups for simple cycle and combined cycle units per month. LADWP would like to clarify whether the proposed limit on "Scheduled Startups" is intended to be in addition to the allowed number of startups specified in the Permit. If it is not SCAQMD's intent to distinguish the emission limits between scheduled startups and other startups, LADWP suggests that the "Scheduled Startup" definition be removed along with associated requirements mentioned in Sections (d)(5) and (e) unless the distinction between scheduled startups and other startups is justified. 4-6

3. Section (c)(9) – Shutdown Definition

"SHUTDOWN means the time period that begins when an electricity generating unit begins reducing load and flue gas temperatures fall below the minimum operating temperature of the NOx post-combustion control equipment, and ends in a period of zero fuel flow."

<u>Comment 1:</u> During diesel readiness testing, there are times when the unit experiences a short period of zero fuel flow when transitioning from natural gas to diesel or diesel to natural gas. LADWP suggests adding the following language to the shutdown definition:

"For dual fuel units, fuel transition period shall not be considered as shutdown." 4-7

<u>Comment 2</u>: LADWP seeks consideration of special permit conditions that allow multiple startups. In cases where a Permit has specific conditions that allow a combined cycle unit to abort a cold start and then restart the unit, the start and restarts count as one cold start provided that the total time does not exceed the cold start permit limit. Since 4-8

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the aborted start ends in zero fuel flow, this constitutes a shutdown per the proposed definition. The subsequent start(s) will then count as a separate cold start assuming that the steam valve does not open during the previous start. If the proposed shutdown language is adopted, the unit will quickly use up its limit of five monthly cold starts. LADWP suggests the following additional language: 4-8 cont.

"For units with specific shutdown language already included in the permit but not captured in this rule, the existing permit language shall be used in determining compliance."

4. Section (d)(3) – Table 2: Startup and Shutdown Duration Limits for Electric Generating Units Installed on or After [DATE OF ADOPTION]

Comment**:** LADWP would like to know if there are permitted units that have achieved the time limits listed in Table 2 and if the time limits are currently listed in the Environmental Protection Agency's Best Available Control Technology Clearing House. If not, LADWP suggests that SCAQMD consider removing Table 2 and amending the rule at a later time when there is sufficient data showing that the limits have been achieved in practice. 4-9

5. Section (d)(4) – End of Startup

"On and after January 1, 2024, an owner or operator of an electric generating unit shall not allow any startup to last longer than the time that is necessary to reach stable conditions and minimum operating temperature of the NOx post-combustion control equipment, if applicable. If a unit reaches stable conditions and the minimum operating temperature of the NOx post combustion control equipment is reached before reaching the startup duration limit specified in paragraphs (d)(2) or (d)(3), the startup period shall be considered over" 4-10

Comment: This rule requirement contradicts the Permit definition of end of startup. LADWP's Permit defines end of startup as the time when the unit achieves the concentration permit limit.

When the post-combustion control equipment such as the Selective Catalytic Reduction (SCR) System reaches its minimum operating temperature, ammonia is injected to the

SCR to reduce NOx emissions so that the unit can achieve compliance with the concentration permit limit within the permitted time limit. The time for the post combustion control equipment to reach its minimum operating temperature is not the

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same as the time it takes for the unit to reach compliance with its emission limit. Compliance with emission limits occurs after ammonia injection has commenced. In addition to ammonia injection, the unit has to reach a minimum load for dry low NOx technology to meet permit limit. For example, combined cycle units commence ammonia injection as early as possible during startup to minimize NOx emissions. Reaching BACT levels which signal the end of startup typically occurs after the unit has ramped up to the minimum load necessary for NOx compliance. LADWP suggests that SCAQMD revise the second sentence in Section (d)(4) as follows: 4-10 cont.

"......If a unit reaches <u>the permit emission concentration limit</u> ~~stable conditions and the minimum operating temperature of the NOx post combustion control equipment is reached~~ before reaching the startup duration limit specified in paragraphs (d)(2) or (d)(3), the startup period shall be considered over."

Alternatively, SCAQMD could revise the definition of "Stable Condition" in Section (c)(10) as follows:

"Stable Condition means that the fuel flow to an electric generating unit is consistent ~~and allows~~ <u>allowing</u> for normal <u>operations and that the unit has reached compliance with emission permit limit."</u>

6. Section (d)(5) – Scheduled Startup Annual Limit

"On and after January 1, 2024, an owner or operator of an electric generating unit shall not exceed two scheduled startups per calendar year for each electric generating unit." 4-11

<u>Comment</u>: As stated in Comment 1 for Section (c)(8), if testing events are considered scheduled startups, the proposed annual limit of two is not sufficient, given the frequency of startups due to these required tests. LADWP is requesting SCAQMD to increase the number of allowed scheduled startups to accommodate scheduled testing listed in the Table A above.

7. Section (e)(1)(A) and (B) - Recordkeeping

"On and after January 1, 2024, an owner or operator of an electricity generating unit shall maintain the following records on-site for 5 years and make this information available to South Coast AQMD upon request: 4-12

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(A) A list of scheduled startups, including date, time, and reason of the scheduled startup and any change(s) to the date and time of the scheduled startup;
(B) An operating log for each startup and shutdown, which contains the date, time, duration, and reason for each event;

Comment: Startup and shutdown date, time and duration are all recorded in the Continuous Emissions Monitoring System (CEMS) Data Acquisition Handling System (DAHS). Requiring maintenance of a separate log for each startup and shutdown seems redundant. A report with this information can be generated from the DAHS. It is unclear why requiring operators of a generating unit to provide the reason for each startup or shutdown is necessary. Operators are already required to provide and maintain records of the date and time of scheduled startups in Section (e)(1)(B). If SCAQMD is concerned about exceedances of startup and shutdown limits, inspectors can verify them by cross-referencing exceedance dates with the scheduled startup date and time records to see if the exceedance is exempt or if it is considered a violation. 4-12 cont.

8. Section (f)(1) – Exemptions for Once-Through-Cooling (OTC) Electric Generating Units to Be Retired

Comment: To allow for flexibility in the event that the State Water Resources Control Board (SWRCB) extends the compliance deadline for the OTC units, LADWP suggests removing the December 31, 2029 date. Referencing the compliance dates set forth in Table 1 of Section 2(B) of the SWRCB's Statewide Water Quality Control Policy on the Use of Coastal Estuarine Waters for Power Plant Cooling (Once-Through-Cooling Policy) implementing Section 316(b) of the Clean Water Act should be sufficient. 4-13

LADWP requests SCAQMD's consideration of these comments and the other stakeholder's comments and looks forward to working with SCAQMD for further development and changes to these rules.

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November 15, 2021

If you have any questions or would like additional information, please contact Ms. Andrea Villarin of my staff at (213) 367-0409 or Ms. Leizl Lontok at (213) 367-3779.

Sincerely,

Katherine Rubin
Digitally signed by Katherine Rubin
Date: 2021.11.15 19:37:28 -08'00'

Katherine Rubin
Manager of Air and Wastewater Quality and Compliance

LL:
c: Ms. Uyen-Uyen Vo (SCAQMD)
Ms. Charlene Nguyen (SCAQMD)
Ms. Andrea Villarin (LADWP)
Ms. Leizl Lontok (LADWP)

Staff Response to Comment Letter 4

Response to Comment 4-1:

The permit reconciliation will require a review and possible revision of individual permit conditions to be consistent with Rule 1135. Staff has determined that 18 months are needed to make the permit revisions for equipment subject to Rule 1135. By extending the application submittal date to January 2023, there would be insufficient time to reconcile permits before rule provisions would become effective. This could lead to facilities seeking variances while their permit was inconsistent with Rule 1135 requirements. Therefore, staff is not extending the application submittal date.

Response to Comment 4-2:

The emission limits will become effective upon issuance of the new permit or January 1, 2024, whichever occurs earlier. It is expected that facilities will also be subject to RECLAIM regulations for some time afterwards concurrently. The permit will reflect both Rule 1135 requirements and RECLAIM requirements that must be met. When the conclusion of RECLAIM occurs, another permit revision will be necessary to remove RECLAIM requirements.

Response to Comment 4-3:

Staff has revised rule language and changed all PAR 1135 references to "fuel oil" to "distillate fuel oil."

Response to Comment 4-4:

Staff has clarified in Chapter 3 of this Staff Report that startups due to periodic source testing, diesel readiness testing, and other regulatory testing are considered scheduled startups. Please refer to Response to Comment 3-7 regarding the number of allowed scheduled startups in PR 429.2 paragraph (d)(5). Additionally, Staff has added a provision in PR 429.2 in paragraph (d)(6) which limits the number of scheduled startups for units required perform distillate fuel oil readiness testing to 64 per year.

Response to Comment 4-5:

Scheduled startup dates can be provided to South Coast AQMD as confidential material not to be shared, disclosed or published pursuant to Gov. Code Sec. 6254(k) and 6255. Scheduled startups may be considered confidential data by some entities. In those cases, the facility is allowed to keep a record of the planned number of scheduled startups by January 1 of each year, but not disclose non-public information (such as specific dates and times of the scheduled startups) until after they have occurred.

Response to Comment 4-6:

The number of scheduled startups will count toward the number of total startups; the number of scheduled startups is not in addition to the number of total startups. Limitations to the number of scheduled startups is an existing requirement in Rule 429 and is carried forward into PR 429.2. Furthermore, limiting the frequency of scheduled startups provides additional bounds to the startup and shutdown provisions.

Response to Comment 4-7:

Staff has revised rule language PR 429.2 paragraph (c)(7) to clarify that for dual fuel electric generating units, a shutdown does not include the time period when the unit transitions from one fuel to another.

Response to Comment 4-8:

Staff has clarified in Chapter 3 of this Staff Report that aborted startups will be addressed in the permit conditions of the unit.

Response to Comment 4-9:

The startup and shutdown duration limits for combined cycle turbines and simple cycle turbines presented in Table 2 are reflected in permits issued by the South Coast AQMD. The equipment subject to these limits have been in operation for more than six months and has demonstrated compliance with the limits. The startup and shutdown duration limits for diesel internal combustion engines are consistent with the startup and shutdown duration limits specified in subparagraph (i)(1)(J) in Rule 1110.2 – Emissions from Gaseous- and Liquid Engines. These limits have not been reported to U.S. EPA as part of any BACT determination as startup durations are generally not included in BACT determinations.

Response to Comment 4-10:

This is a best management practice which will further limit excess emissions from startup events. Best management practices are one of the requirements is the U.S. EPA 2015 Startup, Shutdown, and Malfunction State Implementation Plan Policy.

Response to Comment 4-11:

Please refer to Response to Comment 4-4.

Response to Comment 4-12:

Staff has revised rule language in PR 429.2 subparagraph (e)(1)(B) to require the facility to keep records of each startup and shutdown and no longer requires it in an operating log. Additionally, the rule language removes the requirement for the reason of each startup and shutdown.

Response to Comment 4-13:

The exemption in PR 429.2 paragraph (f)(1) is needed to prevent indefinite extensions of the retirement date of the Once-Through-Cooling Units.

COMMENT LETTER 5

Southern California Edison – December 7, 2021

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

P.O. Box 5085, Rosemead, CA 91770

December 7, 2021

Ms. Susan Nakamura
Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765
Email: SNakamura@aqmd.gov

SUBJECT: Proposed Amended Rule 1135 - Emissions of Oxides of Nitrogen from Electricity Generating Facilities

Proposed Rule 429.2 - Startup and Shutdown Exemption Provisions for Oxides of Nitrogen from Electricity Generating Facilities

Dear Ms. Nakamura:

Southern California Edison (SCE) appreciates the opportunity to comment on the new draft language issued on December 3, 2021 by the South Coast Air Quality Management District (SCAQMD) for Proposed Amended Rule (PAR) 1135 and Proposed Rule (PR) 429.2. SCE remains committed to working with the SCAQMD to comply with the rules.

SCE supports the provisions of the December Draft as they would apply to our combined-cycle gas turbine facility (Mountainview Generating Station) and four simple-cycle gas turbine facilities (Barre, Center, Grapeland, and Mira Loma Peakers). SCE also supports many of the December Draft's proposed requirements for non-emergency diesel internal combustion engines and appreciates that the SCAQMD has recognized the unique operation and challenges at our Pebbly Beach Generating Station ("PBGS") on Santa Catalina Island ("Catalina" or "the Island"). Nonetheless, SCE has significant concerns about the revised draft PAR 1135 issued on December 3, 2021 ("December Draft") and its effect on PBGS. Specifically, SCE believes the December Draft will impede SCE's ability to provide reliable and affordable electric utility service while maintaining environmental stewardship. SCE's analysis to date indicates other zero-emissions technologies are not technically viable or cost effective.

SCE requests the following changes to the December Draft:

- The nitrogen oxides (NOx) emission limit for Electric Generating Units in subparagraph (d)(2)(A) should be increased from 40 tons/year to 53 tons/year.

- The removal of existing Electric Generating Units should be an acceptable alternative to complying with the 13 tons/year facility-wide limit effective on January 1, 2026.
- The reference to "facility-wide" mass emissions should be changed to "mass emission limit from Electric Generating Units."
- The deadline-extension provision should be revised to allow the operation of existing Electric Generating Units as backup units between January 1, 2024 and January 1, 2027.
- An exemption should be created for portable and emergency engines.

Our suggested revisions presented below will take the form of additions shown in **<u>bold underline</u>** text and deletions in ~~strikethrough~~ text.

<u>PAR 1135</u>

A. The proposed facility-wide emissions limit and implementation deadlines should be revised to reflect the current BARCT standard and a practicable timeframe.

The December Draft's reduction of the interim facility-wide NOx limit from 55 tons/year to 40 tons/year (by January 1, 2024) is infeasible given the operations and load requirements at PBGS. In the October Draft, the SCAQMD proposed the replacement of five diesel generators by January 1, 2024 and provided the opportunity to request an extension of up to three years if PBGS's annual NOx emissions did not exceed 55 tons for the 2023 reporting year and thereafter.[1] SCE was not opposed to the October Draft's 55-ton annual emissions limit because it can be reasonably met by replacing Units 8 and 10 (identified as Engines 6 and 1, respectively, in the SCAQMD's 2018 Staff Report) on the current project timeline, assuming a Permit to Construct is issued by June 2022.

In the December Draft, however, SCAQMD has reduced the emissions limit past the point that would allow SCE to meet forecasted electric demand on the Island and comply with PAR 1135 in the required time frame. SCE discusses its significant concerns about the achievability of the new proposed emissions limit below.

1. <u>U.S. EPA Tier 4 Final-certified generator sets are currently considered BARCT for the unique power generating operation at PBGS.</u>

5-1

In its 2018 Staff Report for the initial draft of PAR 1135, the SCAQMD stated that U.S. Environmental Protection Agency (U.S. EPA) Tier 4 Final-certified engines are considered Best

[1] October Draft at subparagraph (d)(3)(A).

unique location and operating challenges of PBGS. However, in the meantime SCE needs to move forward with the proposed project to meet SCAQMD's new requirements and timelines.

Based on the current BARCT analysis conclusions separately reached by the SCAQMD and SCE, SCE intends to replace three engines with U.S. EPA Tier 4 Final-certified generators in order to expeditiously reduce NOx emissions at the facility by January 1, 2024. SCE will continue to conduct additional BARCT analysis to identify other alternative technologies for submission to SCAQMD by January 1, 2023. 5-1 cont'd

2. <u>The new emissions-reduction target of 40 tons/year is infeasible</u>.

In the December Draft, the SCAQMD proposes a NOx emissions limit of 40 tons/year starting on January 1, 2024 (down from 55 tons/year in the October Draft).[6] It is unclear how this 40 tons/year limit was derived. However, based on the SCAQMD's analysis in its 2018 Staff Report, at least five existing generators must be replaced by U.S. EPA Tier 4 Final-certified generators to achieve an annual NOx emissions target of 40 tons/year as shown in Table 1 (69.4 – 30.5 = 38.9 tons).

Taking into account PBGS's configuration, the need for a reliable electricity supply on the Island, anticipated changes to Rule 1135, and all parties' desire for significant near-term emissions reductions, SCE has planned to replace Units 8, 10, and 14 by January 1, 2024. SCE would achieve approximately 16.5 tons of NOx emissions reduction per year upon replacement of the three units. Under this plan, by January 1, 2024, total NOx emissions from the Electric Generating Units at PBGS are projected to be 52.9 tons/year—slightly lower than the 55 tons/year limit proposed in the October Draft. Accordingly, SCE respectfully requests that the NOx emission limit for Electric Generating Units in subparagraph (d)(2)(A) be revised from 40 tons/year to 53 tons/year. The latter target is both ambitious and realistic. 5-2

Table 1. NOx Emissions Profile at PBGS

SCAQMD 2018 Staff Report Unit	SCE Unit	Size (bhp)	2016 Annual NOx Emissions (tons)	NOx Permit Limit (ppmv @ 15% oxygen dry)	Proposed BARCT NOx Emission Limit (ppmv @ 15% oxygen, dry)	Annual Emission Reductions (tons)*
ICE1	Unit 10	1,575	16	6.5 lbs/MWh	45	9.9
ICE3	Unit 14	1,950	5.3	6.5 lbs/MWh	45	2.7
ICE6	Unit 8	2,150	8.2	6.5 lbs/MWh	45	3.9
ICE5	Unit 7	1,500	12	6.5 lbs/MWh	45	5.6
ICE2	Unit 12	2,200	22	6.5 lbs/MWh	45	8.4
ICE4	Unit 15	3,900	5.9	51	45	0.7
Total			69.4			31.2

[6] Compare subparagraph (d)(3)(A) of the October Draft with subparagraph (d)(2)(A) of the December Draft.

3. The reference to "facility-wide" mass emissions should be changed to "mass emission limit from Electric Generating Units."

Separately from the six diesel units, SCE uses other emissions-producing equipment at PBGS such as emergency generators, microturbines, power washers, and other Rule 219 permit-exempt equipment. It is our understanding that the emissions limit proposed in the Rule 1135 amendment pertains to the six Electric Generating Units at PBGS, not to other emission sources. SCE requests that the phrase "facility-wide mass emissions" in subparagraph (d)(2) be changed to "emissions from Electric Generating Units." 5-3

4. Additional analysis must be conducted to confirm whether an annual NOx limit of 13 tons/year is possible.

The December Draft's NOx emissions limit of 13 tons/year (effective January 1, 2026) proposed in subparagraph (d)(2)(c) rests on the assumption that SCE could either (1) implement 100% zero-emissions technologies such as solar or wind power; or (2) connect the Island to the mainland via undersea cables with some backup generation for planned or unplanned outages from the existing diesel generators for up to three months. This assumption may not be accurate and the 13 tons/year emissions limit may not be achievable by the proposed deadline (even with the three-year extension). SCE has learned that maintenance/outage-related downtime associated with an undersea cable could be up to one to two years, so the proposed three-month allowance for backup diesel generation will not suffice. The 13 tons/year cap also assumes the Island's load demand will remain the same in the future. Certain significant load increases are difficult to predict in the future (such as cruise ship electrification, which would be significant and outside of SCE's control). A hard emissions cap would effectively disallow any future load growth. 5-4

Further, SCE opposes the inclusion of a mass emissions cap in addition to concentration-based limits, as the stated goal of the RECLAIM transition was to move away from facility emission caps to command-and-control limits. Imposing both at the same time will add operational (i.e., hourly) restrictions that go above and beyond a command-and-control approach and may impede SCE's ability to reliably serve load and meet compliance requirements.

Finally, subparagraph (d)(2)(B) should be revised to allow major engine maintenance (that could constitute reinstallation or replacement) for new Electric Generating Units so long as it is SCAQMD-approved and meets the BARCT standard at the time of the maintenance.

SCE respectfully requests the following revisions to subparagraph (d)(2):

(2) Electric Generating Units Located on Santa Catalina Island

The owner or operator of an electricity generating facility located on Santa Catalina Island with ~~diesel internal combustion engines~~ **Electric Generating Units** shall:

(A) By January 1, 2024, meet ~~a facility-wide~~ mass emission limit **from Electric Generating Units** of **53** ~~40~~ tons of NOx annually, including mass emissions from startups and shutdowns;

(B) Not install or replace any **Electric Generating Units** ~~diesel internal combustion engines~~ after January 1, 2024 **unless the Electric Generating Unit meets the Best Available Retrofit Control Technology standard and is approved by the Executive Officer**; and

(C) On and after January 1, 2026, **either: remove Electric Generating Units that do not meet the emissions limits in subparagraph (d)(3) and the Best Available Retrofit Control Technology standard in subparagraph (d)(2)(B); OR** meet a ~~facility-wide~~ mass emission limit **for Electric Generating Units** of 13 tons of NOx annually, **including** mass emissions from startups and shutdowns.

5-4 cont'd

B. The deadline-extension provision should be revised to allow the operation of the existing diesel generators as backup units after January 1, 2024.

SCE recognizes the urgency in reducing NOx emissions as soon as January 1, 2024 and we have designed our compliance plan accordingly. However, the revised time-extension provision in the December Draft would prevent SCE from continuing to operate the existing generators (as backups) starting January 1, 2024. SCE requests the reinstatement of the time-extension concept from the October Draft, which would have allowed the existing generators to be used as backups until they are replaced by the new Electric Generating Units that meet the BARCT requirement. This is critical to SCE's ability to serve load and meet all compliance requirements. 5-5

SCE requests the following revisions to subparagraph (d)(4):

(4) Time Extension

(A) The owner or operator of an electricity generating facility on Santa Catalina Island may submit a request to the Executive Officer for a time extension of up to three years to meet the ~~facility-wide mass~~ emissions limits specified in subparagraphs (d)(2)(C) **and (d)(3)**.

C. An exemption should be created for portable and emergency engines.

Although the term "Electric Generating Units" is clearly defined, the term "Diesel Internal Combustion Engines" is used in several locations without reference to the term "Electric Generating Units." This could be misinterpreted to include emergency internal combustion engines and portable engines registered under the California Air Resources Board Statewide Portable Equipment Registration Program ("PERP"), which are critical to the construction and maintenance of SCE's electricity distribution system on the Island. SCE requests that SCAQMD add an explicit exemption for emergency and PERP engines to subparagraph (g)(5): 5-6

(g) Exemptions

(5) **Santa Catalina Island**

(A) Internal combustion engines located on Santa Catalina Island are exempt from subdivision (f).

(B) **The provisions of this rule shall not apply to emergency internal combustion engines and portable engines registered under the California Air Resources Board Statewide Portable Equipment Registration Program (PERP) located on Santa Catalina Island.**

December 7, 2021 Page **8** of **8**

Thank you for your consideration of SCE's comments on the proposed rules. We look forward to continuing to work with you and your staff on this process. If you have any questions or would like to discuss these issues, please contact Joy Brooks, Senior Air Quality Manager at (626) 302-8850 or joy.s.brooks@sce.com.

Sincerely,

DocuSigned by:
Rosalie Barcinas
06DD81A11EA7451...

Rosalie Barcinas
Director of Catalina Operations & Strategy, Generation

CC: Michael Morris, SCAQMD
Uyen-Uyen Vo, SCAQMD
Charlene Nguyen, SCAQMD
Jim Buerkle, SCE
Kenneth Borngrebe, SCE
Dawn Anaiscourt, SCE
Joy Brooks, SCE

Staff Response to Comment Letter 5

Response to Comment 5-1:

The 2018 Rule 1135 amendment established BARCT limits for diesel internal combustion engines in Table 2, which are based on U.S. EPA Tier 4 Final engine certification standards. The Table 2 emission limits allow the operator to implement any technology that can achieve the NOx concentration limit in Table 2. During the development of PAR 1135, SCE was initially planning on replacing all six diesel engines with Tier 4 Final engines to meet the NOx concentration limits in Table 2. Concerns were raised regarding if use of fuel cells or any other non-diesel or near-zero or zero-emission technologies could be implemented instead of replacing engines with new diesel engines. As a result, PAR 1135 was revised to remove the pathway to meet Table 2 NOx limits for diesel internal combustion engines and a two step-process was incorporated. The first step establishes an initial NOx emission cap for the diesel engines of 50 tons per day in 2024 and lowers the cap to 45 tons per day in 2025. It is the South Coast AQMD staff's understanding that to meet this first step, SCE will be replacing two, possibly three, diesel internal combustion engines with U.S. EPA Tier 4 Final-certified engines. The second step is based on a NOx emission cap for the diesel internal combustion engines of 13 tons per year beginning in 2026. Staff is committed to re-initiating rulemaking to do a more detailed technology assessment and BARCT assessment for this second step and to work with stakeholders to evaluate current and emerging near and zero-emission technologies. Staff will be conducting a BARCT assessment during this second step of rulemaking which may change the proposed provisions in subparagraph (d)(2)(D). This approach provides the opportunity to evaluate the best approach to maximize NOx reductions from power generation for Santa Catalina Island, and to reduce and possibly eliminate the use of diesel internal combustion engines.

Staff is including a Resolution to conduct an updated BARCT assessment as soon as practicable for the electric generating units on Catalina Island and to begin the rule development process to amend Rule 1135 in February 2022 to reflect the revised BARCT assessment. Staff thanks SCE for continuing their evaluation of alternative technologies.

Response to Comment 5-2:

Staff has revised PAR 1135 subparagraph (d)(2)(A) to be a mass emission limit of 50 tons of NOx annually from all electric generating units by January 1, 2024 instead of 40 tons of NOx annually by January 1, 2024. To achieve the 50ton per year mass emission cap, SCE would replace two engines with U.S. EPA Tier 4 Final-certified engines (e.g. replacement of Units 8 and 10, which emitted the highest annual emissions in 2016) and rely on operating Unit 15, which has the lowest NOx emission limit among the six existing diesel internal combustion engines and is used most frequently for primary power based on recent historical emissions data provided by SCE. Staff also added another interim mass emission limit of 45 tons of NOx annually from all electric generating units by January 1, 2025 in subparagraph (d)(2)(C) to facilitate further emission reduction after SCE adjusts to operating the lower NO-emitting diesel internal combustion engines to provide primary power.

Response to Comment 5-3:

PAR 1135 will be revised to change "facility-wide mass emissions" to "emissions from Electric Generating Units" in paragraph (d)(2). Currently, the definition for electric generating units does not include the new technology that will replace the engines, but the mass emissions will include emissions from these units. Once the new technology is determined, it will be integrated into the definition of electric generating unit.

Response to Comment 5-4:

PAR 1135 subparagraph (d)(2)(D) will retain the 13 tons per year emission cap as a placeholder. Staff believes that incorporating a provision allowing the operator to determine BARCT is too subjective and provides too much Executive Officer discretion. As previously discussed, staff is committed to re-initiate rulemaking to discuss the second step of reductions for the diesel internal combustion engines. During the rulemaking, staff will evaluate different forms of the emission standard such as a concentration limit or mass emissions cap. The primary concern for RECLAIM was allowing operators use of RECLAIM Trading Credits in lieu of installing pollution controls. It is possible to establish a command-and-control rule with an emissions cap for one or a group of units, which will be consistent with AB 617, provided that each unit is permitted, has specific conditions, and does not allow use or trading of emission credits.

For the initial step of reductions for the diesel internal combustion engines on Catalina Island, Staff has revised PAR 1135 subparagraph (d)(2)(A) to be a mass emission limit of 50 tons of NOx annually from all electric generating units by January 1, 2024 instead of 40 tons. Staff also added another interim mass emission limit of 45 tons of NOx annually from all electric generating units by January 1, 2025 in subparagraph (d)(2)(C). See Response to Comment 5-2 for a more detailed response regarding the proposed mass emission caps.

Staff has also revised PAR 1135 subparagraph (d)(2)(B) to clarify that new diesel internal combustion engines cannot be installed after January 1, 2024 and that diesel engines undergoing reconstruction as defined in 40 CFR Part 60.15 or Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines are not considered "new" diesel engine installations. Lastly, Staff has clarified that mass emission limits are from all electric generating units instead of facility-wide; please see Response to Comment 5-3.

Response to Comment 5-5:

Staff has revised PAR 1135 subparagraph (d)(3)(A) to clarify that on and after January 1, 2024, any new diesel internal combustion engine that is installed to meet the mass emission limits specified in subparagraphs (d)(2)(A), (d)(2)(C), and (d)(2)(D) is required to meet the Table 2 emissions limits. With this added clarification, existing diesel generators that have not been replaced by new electric generating units can still be operated as backup after January 1, 2024 and a time extension for meeting the Table 2 emissions limits is not needed.

Response to Comment 5-6:

Rule 1135 applies to electric generating units, as defined in paragraph (c)(8), at electricity generating facilities. The "Electric Generating Unit" definition in PAR 1135 paragraph (c)(8) includes diesel internal combustion engines, excluding emergency internal combustion engines and portable engines registered under the California Air Resources Board Statewide Portable Equipment Registration Program (PERP). Since Rule 1135 applies to electric generating units and emergency internal combustion engines and portable engines registered under PERP are excluded from the "Electric Generating Unit" definition, adding an explicit exemption for emergency and

PERP engines to subdivision (g) is not necessary. Additionally staff clarified in Chapter 2 of this staff report.

COMMENT LETTER 6

Los Angeles Department of Water and Power – December 7, 2021

LADWP Comments
Proposed Amended Rule 1135 and Proposed Rule 429.2
December 3, 2021

Rule 1135

1. Section d.6– July 1, 2022 Deadline for Submittal of Permit Modifications
   - LADWP requests that Rulemaking staff seek clarification from Permitting Staff regarding the expected permit modifications (i.e. blanket provision that refers to the Rule 1135 applicability OR individual permit conditions that reflect specific provisions under the rule).
   - LADWP would also like to get clarification from Permitting Staff on the amount of time needed to process the permit applications and whether six months would be sufficient. 6-1
   - LADWP also requests that the revised permit conditions (specifically the new NOx concentration limits) specify the implementation/effective date.
2. Section e.F.8 – Operations Recordkeeping
   - LADWP requests that SCAQMD clarify in the staff report that existing reporting formats being used by facilities to provide information to inspectors is acceptable and meets the requirements listed in Section e.F.8. 6-2
   - LADWP requests SCAQMD to clarify acceptable recordkeeping options/processes (eg. source of data/methodology for providing net megawatt-hours of electricity produced).
3. Section (f) (3) – Source Testing
   - LADWP requests that SCAQMD include language that, the fuel meter may be calibrated on an annual basis as an alternative to performing the RATA during diesel firing.
   - In addition, add language to allow RATA to be performed not only during diesel readiness testing but also during force majeure as firing allowed by the permit. 6-3
   - Please refer to the text in bold for suggested edits to the language:

The owner or operator of an electric generating unit shall not be subject to NOx emission limits specified in subdivision (d) when it burns liquid petroleum fuel during emissions source testing, and the electric generating unit may burn liquid petroleum fuel for emissions source testing as specified by South Coast AQMD rules or the Permit to Operate, including initial certifications of Continuous Emissions Monitoring Systems (CEMS) and semi-annual Relative Accuracy Test Audits (RATAs). The owner or operator ***shall*** ~~*only*~~ *conduct RATA tests concurrently with distillate fuel oil readiness testing or during force majeure when diesel firing is allowed by the permit.* ***As an alternative to performing RATA tests during diesel firing, the fuel meter may be calibrated on an annual basis.*** 6-3 cont'd

Rule 429.2

1. Section (c)(6) - Scheduled Startup
   - Please confirm and clarify in the Staff Report that the facility is allowed to keep a record of the planned number of scheduled starts by January 1 of each year, but will not disclose non-public information (specific dates and time of the scheduled starts) until after they have occurred. 6-4
2. Section (d)(4) - End of Startup
   - Stable conditions include the full deployment and implementation of all pollution control equipment. Parameters for establishing stable conditions include but are not limited to ammonia injection, mode 6Q/most efficient natural gas burner firing pattern, NOx water injection, and meeting minimum loads (for NOx compliance) and specific equipment temperatures (i.e. ammonia heater minimum temperature and SCR operating temperature).
   - LADWP proposes the following revised language which ties the end of startup to when the unit meets stable conditions, minimum operating temperature, and full deployment of post-combustion control equipment: 6-5

     If a unit reaches stable conditions, the NOx post-combustion control equipment reaches minimum operating temperature, and ***full deployment of all post-combustion NOx control equipment*** *commences before reaching the startup duration limit specified in paragraph (d)(2), paragraph (d)(3), the Permit to Construct, or the Permit to Operate,* ***whichever startup duration*** *is more stringent, the startup period shall be considered over.*

3. <u>Section d.3 – Startup and Shutdown Limits for Equipment Installed after January 7, 2022</u>
    - This table is focused on existing natural gas technology. LADWP suggests that SCAQMD indicate in the Staff Report that the rule will be amended to account for other technology options in the future. 6-6
4. <u>Section d.5 and d.6 – Maximum No. of Scheduled Startups/Year</u>
    - LADWP suggests revising “required to perform DFO readiness testing” to “permitted to perform DFO readiness testing” 6-7
5. <u>Section (d)(9) – Operation of Post-combustion Equipment</u>
    - Stable conditions include but are not limited to full deployment and implementation of all pollution control equipment which may include ammonia injection, mode 6Q/most efficient natural gas burner firing pattern, NOx water injection, and meeting minimum loads (for NOx compliance) and specific equipment temperatures (i.e. ammonia heater minimum temperature and SCR operating temperature). 6-8
    - Suggested revision to language:
      *On and after January 1, 2024, an owner or operator of an electric generating unit with NOx post-combustion control equipment shall operate the NOx post-combustion control equipment, including <u>**but not limited to**</u> the injection of any associated chemical reagent(s) into the exhaust stream to control NOx, if the temperature of the exhaust gas to the inlet of the NOx post-combustion control equipment is greater than or equal to the minimum operating temperature and the temperature is stable.*

Staff Response to Comment Letter 6

Response to Comment 6-1:

The expected permit modifications will be to individual permit conditions that reflect specific provisions under the rule. Six months evaluation time is insufficient because of the volume of permit applications expected and the review time needed for the U.S. EPA. The estimated evaluation and review time needed is approximately 18 months. Therefore, permit applications needed to reconcile with provisions in Rule 1135 will be required to be submitted by July 1, 2022 to meet the implementation date of January 1, 2024 for most permits. A facility does not need to submit a permit application for reconciliation if the current permit is already reconciled with Rule 1135.

Response to Comment 6-2:

Staff has revised rule language in PAR 1135 paragraph (e)(8) to remove the provision that requires the records be maintained in a manner that is approved by the South Coast AQMD; format for recordkeeping will be determined by the facility.

Records for subparagraph (e)(8)(F), net megawatt-hours electricity produced, can be from either net megawatt meter data or a calculation methodology, using the metered gross megawatt data.

Response to Comment 6-3:

Staff has revised rule language in PAR 1135 paragraph (f)(3) to incorporate fuel meter annual fuel flow meter calibration as a circumstance in which an electric generating unit is allowed to burn liquid petroleum fuel and to allow RATA tests and annual fuel flow calibration to be conducted during force majeure natural gas curtailment when the use of liquid petroleum fuel is required.

Rule 1135 does not have the RATA requirement, that provision is contained in Rule 218-series rules. Therefore, the provision for allowing the fuel meter to be calibrated as an alternative to performing RATA during diesel firing will not be incorporated in PAR 1135.

Response to Comment 6-4:

Please refer to Response to Comment 4-5.

Response to Comment 6-5:

Staff has revised paragraph (d)(4) to include full deployment and implementation of all pollution control equipment to clarify the meaning of stable conditions. Staff also clarified that the provision applies only to the duration of the startup.

Response to Comment 6-6:

Staff concurs that the duration limits in Table 2 of Rule 429 are for turbines and boilers firing on natural gas. If hydrogen or another gaseous fuel were to be utilized, the duration limits would need to be revisited in a future rule amendment. Staff did not include duration limits for other turbine and boiler fuels as there are no units burning alternative gaseous fuels at this time and it is not known if duration times would need to be altered.

Response to Comment 6-7

Staff has revised the provision as requested to reference permitted units.

<u>Response to Comment 6-8:</u>

Staff has revised language as requested. Stable conditions necessary to require the operation of post-combustion control equipment include full deployment of all pollution control equipment such as ammonia injection, water injection, steam injection, burner firing pattern, minimum loads, and specific equipment operating temperatures. These conditions are not applicable immediately upon occurrence but when they can be maintained at a steady state.