(Adopted August 4, 1989)(Amended December 21, 1990)(Amended July 19, 1991)
(PAR 1135 v 09-22-18)

PROPOSED AMENDED RULE 1135. EMISSIONS OF OXIDES OF NITROGEN FROM ~~ELECTRIC POWER GENERATING SYSTEMS~~ ELECTRICITY GENERATING FACILITIES

(a) Purpose

The purpose of this rule is to reduce emissions of oxides of nitrogen (NO_x) from electric generating units at electricity generating facilities.

(~~a~~b) Applicability

This rule shall ~~applies~~ apply to electric ~~power~~ generating ~~systems~~units at electricity generating facilities. This rule shall not apply to petroleum refineries as identified by the North American Industry Classification System Code 324110, Petroleum Refineries.

(~~b~~c) Definitions

~~(1) ADVANCED COMBUSTION RESOURCE means a combustion resource, within or outside the District, irrespective of ownership, capable of generating electricity using cogeneration; combined cycle gas turbines; intercooled, chemically recuperated, or other advanced gas turbines; and other advanced combustion processes.~~

~~(2) ALTERNATIVE RESOURCE means a resource, within or outside the District, irrespective of ownership, capable of generating electricity in a non-conventional manner, including, but not limited to: solar; geothermal; wind; fuel cells; electricity conservation; and electricity demand-side management measures.~~

~~(3) APPROVED ALTERNATIVE OR ADVANCED COMBUSTION RESOURCE means an alternative resource or advanced combustion resource which is approved by the Executive Officer. The Executive Officer shall disapprove an alternative resource or an advanced combustion resource unless and until it:~~

~~(A) Displaces boiler capacity existing in the District on or after July 19, 1991; and~~

~~(B) Emits~~ ~~NO_x~~ ~~at no more than 0.10 pound per net megawatt-hours (MWH) on a daily average basis if the resource is located within the District, or no more than 0.05 pound per net MWH on a daily average basis if the resource is located outside the District; for cogeneration facilities, the daily~~ ~~NO_x~~ ~~emission per MWH shall be calculated after deducting 0.013 pound of~~ ~~NO_x~~ ~~for each million BTU of useful thermal energy produced which is not used for electric power generation; and~~

~~(C) Commences operation on or after July 19, 1991; and~~

~~(D) Is proven to the satisfaction of the Executive Officer that the net megawatt-hours obtained or conserved are real, quantifiable, and enforceable.~~

~~(4) ALTERNATIVE RESOURCE OR ADVANCED COMBUSTION RESOURCE BREAKDOWN means an unscheduled condition during which no net electric power is obtained from an approved alternative or advanced combustion resource for 24 continuous hours or more.~~

(1) ANNUAL CAPACITY FACTOR means the ratio between the measured heat input (in MMBTU) from fuel consumption to an electric generating unit during a calendar year and the potential heat input (in MMBTU) to the electric generating unit had it been operated for 8,760 hours during a calendar year at the permitted heat input rating, expressed as a percent. Annual capacity factor does not include heat input of the electric generating unit during the Emergency Phase of the California Energy Commission Energy Emergency Response Plan or a Governor-declared State of Emergency or Energy Emergency.

(~~5~~2) BOILER means any combustion equipment ~~in the District~~ fired with liquid and/or gaseous fuel, which is primarily used to produce steam that is expanded in a turbine generator used for electric power generation. ~~This includes only units existing on July 19, 1991, which are owned or operated by any one of the following: Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Glendale, and City of Pasadena, or any of their successors.~~

~~(6) COGENERATION FACILITY means equipment used to produce electricity and other forms of useful thermal energy through the sequential use of energy, as specified in Public Resources Code Section 25134.~~

(3) COGENERATION TURBINE means any gas turbine which is designed to generate electricity and useful heat energy at the same time (combined heat and power).

(4) COMBINED CYCLE GAS TURBINE means any gas turbine that recovers heat from the gas turbine exhaust gases for use in a heat recovery steam generator to generate additional electricity.

(~~7~~5) DAILY means a calendar day starting at 12 midnight and continuing through to the following ~~12 midnight hour~~ 11:59 p.m.

~~(8) DISPLACE means either of the following:~~

~~(A) The concurrent and enforceable reduction of equivalent boiler capacity from one or more designated boilers in the District, such that the combined electric power obtained from approved alternative or advanced combustion resources and designated boilers does not exceed the maximum permitted capacity of the designated boilers, on an hourly average basis; or~~

~~(B) The reduction of boiler capacity, equivalent to the maximum electric power obtained from the approved alternative or advanced combustion resource, from one or more boilers in the District for not less than six months as specified in the Permit to Operate. The owner or operator of the boilers may apply to the Executive Officer for restoration of the displaced capacity in the Permit to Operate, which shall be approved upon:~~

~~(i) Disapproval of the previously approved alternative or advanced combustion resource which was based on such displaced capacity; and~~

~~(ii) Evidence of compliance with all provisions of this rule after the restoration of the displaced capacity.~~

~~During an alternative or advanced combustion resource breakdown, the associated displaced boiler capacity may be utilized up to a maximum of 120 hours in any calendar month, provided the Executive Officer is notified prior to such utilization.~~

(6) DUCT BURNER means a device located in the heat recovery steam generator of a gas turbine that combusts fuel and adds heat energy to the turbine exhaust to increase the output of the heat recovery steam generator.

~~(9) DISTRICT-WIDE DAILY LIMITS means the daily emissions limits applicable to any electric power generating system, consisting of an emissions cap and/or an emissions rate.~~

~~(A) EMISSIONS CAP is expressed in pounds of~~ $\cancel{NO_x}$ ~~and calculated as the total daily~~ $\cancel{NO_x}$ ~~emissions in pounds from all boilers, replacement units, and approved alternative or advanced combustion resources in the District.~~

~~(B) EMISSIONS RATE is expressed in pounds of~~ $\cancel{NO_x}$ ~~per Megawatt-Hour and calculated as the total daily~~ $\cancel{NO_x}$ ~~emissions in pounds from all boilers, replacement units, and approved alternative or advanced combustion resources in the District, divided by the total daily net electric power generated and/or obtained in Megawatt-Hours from all boilers and replacement units in the District and approved alternative or advanced~~

~~combustion resources within or outside the District. For the purposes of this calculation, 70 percent, or higher if proven to the satisfaction of the Executive Officer, of the net Megawatt-Hours obtained from an approved alternative or advanced combustion resource outside the District shall be used. NO_x emissions during start-ups and shutdowns, up to a maximum of 12 hours for each event, shall not be included in the determination of the emissions rate for an electric power generating system if five or fewer boilers are in operation during this period.~~

~~NO_x emissions from approved cogeneration facilities shall be calculated after deducting 0.013 pound of NO_x for each million BTU of useful thermal energy produced which is not used for electric power generation.~~

(7) ELECTRICITY GENERATING FACILITY means a facility that is owned or operated by an investor-owned electric utility; 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.

~~(10) ELECTRIC POWER GENERATING SYSTEM means all boilers, replacement units and approved alternative or advanced combustion resources owned or operated by, and approved alternative or advanced combustion resources and replacement units under contract to sell power to, any one of the following: Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any of their successors.~~

(8) ELECTRIC GENERATING UNIT means a boiler that generates electric power, gas turbine that generates electric power with the exception of cogeneration turbines, or diesel internal combustion engine that generates electric power and is located on Santa Catalina Island with the exception of emergency internal combustion engines.

(~~11~~9) FORCE MAJEURE NATURAL GAS CURTAILMENT means an interruption in natural gas service due to unforeseeable failure, malfunction, or natural disaster, not resulting from an intentional or negligent act or omission on the part of the owner or operator of an ~~boiler or a replacement unit~~ electric generating unit, or a supply restriction resulting from a California Public Utilities Commission (CPUC) priority allocation system of CPUC Rule 23, such that the daily fuel needs of an ~~boiler or a replacement unit~~electric generating unit cannot be met with the natural gas available.

(10) FORMER RECLAIM NO_x SOURCE for the purpose of this rule means an electric generating unit located at an electricity generating facility or its successor that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a final determination notification from the Executive Officer, and is no longer in the RECLAIM program.

(11) INTERNAL COMBUSTION ENGINE means a reciprocating type engine in which the combustion of a fuel occurs with an oxidizer (usually air) in a combustion chamber to produce mechanical energy.

(12) INVESTOR-OWNED ELECTRIC UTILITY means a business organization managed as a private enterprise that operates electric generating unit(s) for electric power distribution primarily in the grid system overseen by the California Public Utilities Commission.

(13) NON-RECLAIM NO_x SOURCE for the purpose of this rule means an electric generating unit located at an electricity generating facility or its successor that was not in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.

(~~12~~14) OXIDES OF NITROGEN (NO_x) EMISSIONS means the sum of nitric oxides and nitrogen dioxides emitted, collectively expressed as nitrogen dioxide emissions.

~~(13) REPLACEMENT UNIT for the purpose of this rule means equipment within an electric power generating system, irrespective of ownership, which permanently replaces boiler capacity existing on July 19, 1991 in the same system in the District, and meets the requirements of Best Available Control Technology (BACT), as determined by the Executive Officer. If the replacement unit's electric power output in net megawatts exceeds the permitted net megawatt capacity of the boiler(s) replaced, only the electric power generation and NO_x emissions prorated to the permitted net megawatt capacity of the boiler(s) replaced shall be subject to the provisions of this rule.~~

(15) PUBLICLY OWNED ELECTRIC UTILITY means a special-purpose district or other jurisdiction, including municipal districts, that operates electric generating unit(s) for electric power distribution, either partially or totally, to residents of that district or jurisdiction.

(16) RECLAIM NO_x SOURCE for the purpose of this rule means an electric generating unit located at an electricity generating facility or its successor that is in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.

(17) SCAQMD-WIDE DAILY LIMITS means the daily emissions limits applicable to any electricity generating facility consisting of an emissions cap and/or an emissions rate.

(A) EMISSIONS CAP is expressed in pounds of NO_x and calculated as the total daily NO_x emissions in pounds from all boilers at an electricity generating facility.

(B) EMISSIONS RATE is expressed in pounds of NO_x per Megawatt-Hour and calculated as the total daily NO_x emissions in pounds from all boilers at an electricity generating facility, divided by the total daily net electric power generated and/or obtained in Megawatt-Hours from all boilers at an electricity generating facility. NO_x emissions during start-ups and shutdowns, up to a maximum of 12 hours for each event, shall not be included in the determination of the emissions rate for an electricity generating facility if five or fewer boilers are in operation during this period.

(18) SHUTDOWN means the time period during which an electric generating unit reduces load ending in a period of zero fuel flow or as otherwise defined in the SCAQMD permit.

(19) SIMPLE CYCLE GAS TURBINE means any stationary combustion turbine that does not recover heat from the combustion turbine exhaust gases to heat water or generate steam.

(~~14~~20) START-UP ~~OR SHUTDOWN is any one of the following events:~~

~~(A)~~ ~~START-UP is~~ means the time period ~~during which~~ that begins when an ~~boiler~~ electric generating unit ~~is heated to its normal operating temperature range from a cold or ambient temperature, or from a hot standby condition where no net electric power is produced for at least 8 hours~~ begins combusting fuel after a period of zero fuel flow and ends when the electric generating unit generates electricity for sale over the grid for power distribution, or as otherwise defined in the SCAQMD permit.

~~(B)~~ ~~SHUTDOWN is the time period during which a boiler is allowed to cool from its normal operating temperature range to a cold or ambient temperature, or to a hot standby condition where no net electric power is produced for at least 8 hours.~~

(21) TUNING means adjusting, optimizing, rebalancing, or other similar operations to an electric generating unit or an associated control device or as otherwise defined

in the SCAQMD permit. Tuning does not include normal operations to meet load fluctuations.

~~(15) USEFUL THERMAL ENERGY means thermal energy used in any industrial or commercial process, or used in any heating or cooling application. This shall not include the thermal energy of any condensate returned from the process or application to the cogeneration facility, or any thermal energy used to produce electric power.~~

(~~c~~d) Emissions ~~Limitations~~ Limits

(1) Emissions Limits for Boilers and Gas Turbines

Notwithstanding the exemptions contained in Rule 2001 – Applicability, subdivision (j) – Rule Applicability and its accompanying Table 1 – Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NO_x Emissions, on or before January 1, 2024, the owner or operator of an electricity generating facility shall not operate, excluding during start-up, shutdown, and tuning, a boiler or gas turbine in a manner that exceeds the NO_x and ammonia emissions limits listed in Table 1 – Emissions Limits for Boilers and Gas Turbines, where:

(A) Boilers and gas turbines installed after [*Date of Adoption*] shall average the NO_x and ammonia emissions limits in Table 1 over a 60 minute rolling average; or

(B) Boilers and gas turbines installed prior to [*Date of Adoption*] may retain the averaging time requirements specified on the SCAQMD permit as of [*Date of Adoption*]; and

Table 1: Emissions Limits for Boilers and Gas Turbines

Equipment Type	**NO_x (ppmv)**	**Ammonia (ppmv)**	**Oxygen Correction (%, dry)**
Boiler	5	5	3
Combined Cycle Gas Turbine and Associated Duct Burner	2	5	15

Simple Cycle Gas Turbine	2.5	5	15

(2) Emissions Limits for Diesel Internal Combustion Engines Located on Santa Catalina Island

(A) Notwithstanding the exemptions contained in Rule 2001 – Applicability, subdivision (j) – Rule Applicability and its accompanying Table 1 – Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NO_x Emissions, on or before January 1, 2024, the owner or operator of an electricity generating facility located on Santa Catalina Island shall not operate, excluding during start-up, shutdown, and tuning, a diesel internal combustion engine in a manner that exceeds the NO_x, ammonia, carbon monoxide, volatile organic compounds, and particulate matter emissions limits listed in Table 2 – Emissions Limits for Diesel Internal Combustion Engines Located on Santa Catalina Island.

(B) Internal combustion engines located on Santa Catalina Island installed prior to [*Date of Adoption*] may retain the averaging time requirements specified on the SCAQMD permit as of [*Date of Adoption*].

Table 2: Emissions Limits for Diesel Internal Combustion Engines Located on Santa Catalina Island

NO_x[1] (ppmv)	Ammonia[1] (ppmv)	Carbon Monoxide[2] (ppmv)	Volatile Organic Compounds[3] (ppmv)	Particulate Matter (lbs/mmbtu)
45	5	250	30	0.0076

1 – Corrected to 15% oxygen on a dry basis and averaged over a 60 minute rolling average

2 – Corrected to 15% oxygen on a dry basis and averaged over 15 minutes

3 – Measured as carbon, corrected to 15% oxygen on a dry basis, and averaged over sampling time required by the test method

(3) Start-up, Shutdown, and Tuning Requirements

The owner or operator of an electricity generating facility shall meet start-up, shutdown, and tuning requirements in the SCAQMD permit for each electric generating unit. The SCAQMD permit shall include limitations for duration, mass emissions, and number of start-ups, shutdowns, and, if applicable, tunings.

(4) Alternative Compliance Approach for 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 that elects to meet an actual mass emission limit of 13 tons of NO_x annually by January 1, 2026 in lieu of complying with paragraph (d)(2)(A) shall:

(A) On or before January 1, 2022, submit a written notification to the Executive Officer that specifies the decision to meet a mass emission limit of 13 tons of NO_x annually by January 1, 2026; provides a description of the technologies that will be implemented to meet the emission limits; and provides schedule of submittal of permits to the SCAQMD and any other approving agency, timeframe to order equipment, and timeframe for installation of equipment that will demonstrate the facility can meet a mass emission limit of 13 tons of NO_x annually by January 1, 2026; and

(B) On or before January 1, 2022 for, submit an application and abide by, a permit condition that limits total annual emission from the facility to no more than 13 tons of NOx emission annually after December 31, 2025.

(5) Time Extensions

(A) The owner or operator of an electricity generating facility on Santa Catalina Island may submit a request to the Executive Officer for approval of up to three years extension to meet the emissions limits specified in paragraphs (d)(2) or (d)(4):

(i) If electing to comply with paragraph (d)(2), a minimum of two units, excluding units exempt under paragraph (g)(3), meet the emissions limits in Table 2 by January 1, 2023; or

(ii) If electing to comply with paragraph (d)(4), meet an actual mass emission limit of 50 tons of NO_x annually for compliance year 2022, and meet an actual mass emission limit of 40 tons of NO_x annually for compliance year 2023.

(B) The owner or operator that elects to submit a request for a time extension shall submit the request at least 365 days before the compliance deadline specified in paragraphs (d)(2)(A) or (d)(4)(A).

(C) The owner or operator that submits a request for a time extension request shall provide the following information to the Executive Officer:

(i) Identification of the units for which a time extension is needed;

(ii) The reason(s) a time extension is needed;

(iii) Progress of replacing or retrofitting the electric generating units; and

(iv) The length of time requested.

(D) The Executive Officer will approve or disapprove the request for a time extension. Approval or rejection will be based on the following criteria:

(i) The owner or operator prepared the request for a time extension in compliance with subparagraphs (d)(5)(A) through (d)(5)(C); and

(ii) The owner or operator provided sufficient details identifying the reason(s) a time extension is needed that demonstrates to the Executive Officer that there are specific circumstances beyond the control of the owner or operator that necessitate additional time to complete implementation of the plan. Such a demonstration may include, but is not limited to, providing detailed schedules, engineering designs, construction plans, land acquisition contracts, permit applications, and purchase orders.

(E) If the Executive Officer approves the request for a time extension, the owner or operator shall:

(i) Submit an application and abide by, a permit condition that limits total annual emission from the facility to no more than 13 tons of NOx emission annually after the time extension; and

(ii) Pay a mitigation fee within 30 days of the date of approval. The mitigation fee shall be $100,000/year, or any portion of a year, after the compliance date specified in paragraphs (d)(2)(A) or (d)(4)(A).

~~(1) Southern California Edison, or its successor, shall not operate its electric power generating system unless the following District-wide daily limits on emissions rate and emissions cap are met during the applicable time period:~~

	~~District-Wide Daily Limits Lb NOx/Net Megawatt (MW) Hr~~	~~Lb NO$_x$ Per Day~~
~~Beginning December 31, 1989~~	~~1.10~~	
~~Beginning December 31, 1990~~	~~1.01~~	
~~Beginning December 31, 1991~~	~~0.91~~	
~~Beginning December 31, 1992~~	~~0.82~~	

~~Beginning December 31, 1993~~	~~0.72~~	
~~Beginning December 31, 1994~~	~~0.63~~	
~~Beginning December 31, 1995~~	~~0.53~~	
~~Beginning December 31, 1996~~	~~0.44~~	
~~Beginning December 31, 1997~~	~~0.34~~	
~~Beginning December 31, 1998~~	~~0.25~~	
~~Beginning December 31, 1999~~	~~0.15~~	~~13,400~~

~~(2)~~ ~~Los Angeles Department of Water and Power, or its successor, shall not operate its electric power generating system unless the following District-wide daily limits on emissions rate and emissions cap are met during the applicable time period:~~

	~~District-Wide Daily Limits Lb NO_x/Net Megawatt (MW) Hr~~	~~Lb NO_x Per Day~~
~~Beginning December 31, 1989~~	~~1.60~~	
~~Beginning December 31, 1990~~	~~1.41~~	
~~Beginning December 31, 1991~~	~~1.21~~	
~~Beginning December 31, 1992~~	~~1.02~~	
~~Beginning December 31, 1993~~	~~0.82~~	
~~Beginning December 31, 1994~~	~~0.73~~	
~~Beginning December 31, 1995~~	~~0.63~~	
~~Beginning December 31, 1996~~	~~0.54~~	
~~Beginning December 31, 1997~~	~~0.43~~	
~~Beginning December 31, 1998~~	~~0.29~~	
~~Beginning December 31, 1999~~	~~0.15~~	~~5,400~~
~~Beginning December 31, 2004~~	~~0.15~~	~~6,400~~
~~Beginning December 31, 2009~~	~~0.15~~	~~7,400~~

(~~3~~6) City of Glendale

(A) Until compliance with the provisions pursuant to paragraph (d)(1) is achieved, ~~The City of Burbank,~~ the City of Glendale~~, and the City of Pasadena,~~ or any of ~~their~~ its successors, shall not operate ~~their~~ its boilers ~~electric power generating system~~ unless at least one of the following

~~District~~SCAQMD-wide daily limits on emissions rate or emissions cap is met ~~during the applicable time period~~:

~~(A)~~ ~~For the City of Burbank:~~

~~Date~~	~~District-Wide Daily Limits~~	
	~~Lb NO_x/Net Megawatt (MW) Hr~~	~~Lb NO_x Per Day~~
~~Beginning December 31, 1989~~	~~2.47~~	~~3,870~~
~~Beginning December 31, 1993~~	~~1.73~~	~~2,763~~
~~Beginning December 31, 1996~~	~~0.99~~	~~1,657~~
~~Beginning December 31, 1999~~	~~0.20~~	~~580~~

~~(B)~~ ~~For the City of Glendale:~~

~~Date~~	~~District-Wide Daily Limits~~	
	~~Lb NO_x/Net Megawatt (MW) Hr~~	~~Lb NO_x Per Day~~
~~Beginning December 31, 1989~~	~~2.52~~	~~2,940~~
~~Beginning December 31, 1993~~	~~1.76~~	~~2,050~~
~~Beginning December 31, 1996~~	~~1.00~~	~~1,170~~
~~Beginning December 31, 1999~~	~~0.20~~	~~390~~

(A) Emissions rate of 0.20 pounds of NO_x per net Megawatt-Hour; or

(B) Emissions cap of 390 pounds of NO_x per day.

~~(C)~~ ~~For the City of Pasadena:~~

~~Date~~	~~District-Wide Daily Limits~~	
	~~Lb NO_x/Net Megawatt (MW) Hr~~	~~Lb NO_x Per Day~~
~~Beginning December 31, 1989~~	~~3.05~~	~~5,230~~
~~Beginning December 31, 1993~~	~~2.12~~	~~3,680~~
~~Beginning December 31, 1996~~	~~1.18~~	~~2,130~~
~~Beginning December 31, 1999~~	~~0.20~~	~~900~~

(~~4~~B) ~~Electric power generating systems~~ Until compliance with the provisions pursuant to paragraph (d)(1) is achieved, the City of Glendale shall not emit total quantities of NO_x from all boilers~~, replacement units and approved alternative resources or advanced combustion resources in the~~

~~District, for any calendar year beginning with 2000,~~ in excess of ~~the following limits:~~

~~(A) 1,640 tons per year for Southern California Edison Co.;~~

~~(B) 960 tons per year for Los Angeles Department of Water and Power;~~

~~(C) 56 tons per year for the City of Burbank;~~

~~(D)~~ 35 tons of NO_x per calendar year ~~for the City of Glendale;~~.

~~i~~If Grayson combined cycle gas turbine Unit 8BC cannot produce electricity because of a breakdown for 30 continuous days or more, the annual NO_x emissions limit shall be increased by 65 pounds per day, up to a maximum of 41 tons per year.

~~(E) 80 tons per year for the City of Pasadena.~~

(~~5~~C) A violation of any requirement specified in subparagraphs ~~(c)(1), or (c)(2), or (c)(3), or (c)(4)~~ (d)(6)(A) or (d)(6)(B) shall constitute a violation of this rule for every ~~permitted~~ applicable unit operating during the exceedance period ~~in the applicable electric power generating system~~. ~~This provision shall not be applicable to approved alternative or advanced combustion resources, and compliance shall be determined assuming that NO_x emissions from approved alternative or advanced combustion resources occur at actual or permitted levels, whichever is lower.~~

~~(6) All retrofit emission control devices required to meet the provisions of this rule for the year 2000 shall be installed and be operative on each boiler by December 31, 1997, except for the three cities of Glendale, Pasadena and Burbank for whom the deadline shall be December 31, 1999. All replacement units and approved alternative or advanced combustion resources required by the approved compliance plan for all the electric power generating systems shall be installed and be operative by December 31, 1999.~~

(7) On or before July 1, 2022, ~~The~~ the owner or operator ~~of each boiler and approved alternative or advanced combustion resource in the District~~ an electricity generating facility shall submit an application for change of permit conditions to reconcile their permit with Rule 1135. ~~include NO_x emission limits for each boiler and approved alternative or advanced combustion resource, as specified in the compliance plan requirements in subparagraph (d)(1)(C). Such applications shall be submitted no later than January 1, 1992, to the Executive Officer for approval.~~

~~(8) A violation of any unit specific NO_x emissions limits established in a District Permit to Operate or approved compliance plan shall constitute a violation of this rule for that unit of the electric power generating system.~~

~~(d) Compliance Plans~~

~~(1) Compliance Plan (Plan) approval and disapproval:~~

~~(A) Each owner or operator of a boiler shall submit a Plan by January 1, 1992 to the Executive Officer for approval. The Plan shall propose actions and alternatives which will be taken to meet or exceed the requirements of this rule.~~

~~(B) The Executive Officer shall seek input from the Air Resources Board (ARB), the California Energy Commission (CEC), and the California Public Utilities Commission (CPUC) prior to approval of the Plan. All written comments received from the ARB, the CEC, and the CPUC for a CPUC-regulated utility, within 30 days of the receipt of the Plan, shall be considered by the Executive Officer for Plan approval.~~

~~(C) The Executive Officer shall disapprove the Plan unless the applicant proves to the satisfaction of the Executive Officer that the implementation of the Plan will result in timely compliance with all provisions of this rule. The approved Plan shall specify a NO_x emission limit for each unit of the electric power generating system in Lb NO_x per net Megawatt Hour on an hourly average basis; such emission limit shall not be applicable when the unit is not producing any net electric power, or during a start-up, a shutdown, or 12 hours for each start-up or shutdown, whichever is less.~~

~~(D) On and after July 1, 1992, failure to have an approved Plan or failure to implement the provisions of an approved Plan shall constitute a violation of this rule.~~

~~(2) The Plan shall contain, at a minimum:~~

~~(A) A list of all boilers subject to this rule with the maximum rated net and gross generating capacity for each unit.~~

~~(B) A schedule of equipment to be controlled, displaced, or replaced, indicating the type of control to be applied to each existing boiler and the emissions reductions for each compliance increment, and identifying each unit to be displaced with an alternative or advanced combustion resource.~~

~~(C) Detailed schedules for submittal of permit applications, construction activities, and planned operation phases.~~

~~(D) A detailed list of all assumptions and calculations used to determine compliance with the District-wide daily limits.~~

(E) ~~A list of the control devices and methods which are being proposed for each boiler specified in subparagraph (d)(2)(A), along with the percent~~ ~~NO_x reduction efficiency assumed for each.~~

(F) ~~Historical power generating data for each boiler and future resource plans used to support power generation mix assumptions.~~

(G) ~~For each year, beginning with 1992, a graph of the NO_x emission in Lb NO_x/hour versus net Megawatts generated on an hourly average basis for the full load range of each unit of the electric power generating system burning natural gas that will result in compliance with the District-wide daily limits as specified in subsection (c), Emissions Limitations, for the following cases:~~

(i) ~~Under a projected peak generation day for each future year of compliance, based on District guidelines, and~~

(ii) ~~Individually for each unit, under maximum power generation for that unit on a projected peak generation day for each future year of compliance.~~

(H) ~~Identification of conditions that may require an exemption under subsection (h) and the actions taken or to be taken to minimize or eliminate such conditions.~~

(3) ~~The Plan shall also include proposed increments of progress for the following:~~

(A) ~~Southern California Edison shall install and operate by December 31, 1993 a Selective Catalytic Reduction unit (SCR) on an existing 480 MW steam boiler such that NO_x emissions from the facility do not exceed 0.25 pound of NO_x per net MWH; and~~

(B) ~~Los Angeles Department of Water and Power shall replace at least 240 megawatts of existing steam boiler capacity by December 31, 1993 such that NO_x emissions from the replacement unit do not exceed applicable Best Available Control Technology standards, as determined by the Executive Officer.~~

(4) ~~Not earlier than July 1 of any year following 1992, amendments to a previously approved Plan may be proposed to the Executive Officer as necessary to reflect energy regulatory agency resource or municipal authority planning determinations, adjustments to unit specific emissions limits required in subparagraph (d)(1)(C) in view of emissions control performance test data, and advancements in emissions control technology. The Executive Officer shall disapprove such amendments unless the applicant proves to the satisfaction of the Executive Officer that the~~

~~implementation of the amended Plan will result in timely compliance with all provisions of this rule.~~

~~(5)~~ ~~All approved Plans and approved amendments to Plans shall be submitted by the District to the Air Resources Board and the Environmental Protection Agency as source-specific revisions to the State Implementation Plan.~~

(e) ~~Measurements~~Monitoring, Recordkeeping, and Reporting

(1) The owner or operator of an electricity generating facility shall maintain information pursuant to this subdivision at the facility for a period of five years and make available to SCAQMD upon request.

~~(1)~~ ~~The owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District power shall install, operate, and maintain in calibration an continuous emission monitoring system (CEMS) and a Remote Terminal Unit (RTU) to demonstrate compliance with the provisions of this rule.~~

~~(2)~~ ~~Each CEMS shall meet all applicable federal, state and District requirements for certification, calibration, performance, measurement, maintenance, notification, recordkeeping, and reporting, including, but not limited to, the requirements set forth in the District's "CEMS Requirements Document for Utility Boilers," dated July 19, 1991. Prior to the installation of a CEMS, the owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall submit a revised detailed CEM Plan by October 19, 1991 for the approval of the Executive Officer. The CEM Plan shall contain all information required in the District's "CEMS Requirements Document for Utility Boilers," dated July 19, 1991.~~

~~(3)~~ ~~Each RTU shall meet specifications set forth by the Executive Officer to ensure that emissions and other data necessary to determine compliance are reliably and accurately telecommunicated from each unit to the District in a format compatible with District equipment. Each RTU shall be installed with the prior approval of the Executive Officer by January 1, 1993.~~

~~(4)~~ ~~Starting December 21, 1990 until January 1, 1993, the owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall submit a monthly compliance report to the Executive Officer, and shall make all data available to the District staff on a daily basis according to the interim reporting requirements specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991.~~

~~(5) The owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall install testing facilities as specified in the "CEMS Requirements Document for Electric Generating Units," dated July 19, 1991, by January 1, 1993.~~

~~(6) The owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall install, maintain and operate a backup data gathering and storage system after each associated RTU is installed, but not later than January 1, 1993, as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991.~~

~~(7) CEMS data shall be gathered and recorded at least once per minute at each boiler, replacement unit and approved alternative or advanced combustion resource in the District, and valid data, as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991, shall be obtained for at least 90 percent of the data points in any calendar day.~~

~~(8) If valid data is not obtained by a CEMS for any boiler, replacement unit or approved alternative or advanced combustion resource in the District, the following alternative means of~~ NO_x ~~emissions data generation may be used for not more than 72 hours in any one calendar month:~~

- ~~(A) Reference test methods as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991; or~~
- ~~(B) Load curves provided approval is obtained as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991. New load curves shall be submitted for the approval of the Executive Officer if the basic equipment is modified.~~

(2) RECLAIM NO_x Source and Former RECLAIM NO_x Source

The owner or operator of each RECLAIM NO_x source and former RECLAIM NO_x source subject to Rule 1135 shall comply with SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NO_x) Emissions to demonstrate compliance with the NOx emissions limits of this rule, excluding the following:

- (A) Paragraphs (c)(3) through (c)(8), reporting and Super Compliant facilities;
- (B) Subparagraphs (d)(2)(B) through (d)(2)(E), reporting and emission factors;
- (C) Subdivisions (e), NO_x Process Units;
- (D) Paragraphs (g)(5) through (g)(8), reporting;
- (E) Paragraphs (h)(1), (h)(2), and (h)(4) through (h)(6), reporting and mass emissions;

(F) Subdivisions (k) and (l), Exemptions and Appeals; and

(G) Reported Data and Transmitting/Reporting Frequency requirements from Appendix A – "Protocol for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_x) Emissions."

(3) Non-RECLAIM NO_x Source

The owner or operator of a non-RECLAIM NO_x source subject to Rule 1135 shall comply with the following provisions to demonstrate compliance with the NOx emissions limits of this rule:

(A) Comply with 40 CFR Part 75 and calculate NOx in ppmv pursuant to SCAQMD Rule 218 – Continuous Emission Monitoring; or

(B) SCAQMD Rule 218 – Continuous Emission Monitoring.

(4) City of Glendale

The City of Glendale or any of its successors shall demonstrate compliance with paragraph (d)(6) and calculate NOx emissions rate in pounds per net Megawatt-Hour or NOx emissions cap in pounds of NOx per day and tons of NOx per calendar year as established in their approved Continuous Emission Monitoring System (CEMS) Plan.

(5) Internal Combustion Engines Located on Santa Catalina Island

The owner or operator of each internal combustion engine electric generating unit shall comply with the following provisions:

(A) Demonstrate compliance with the carbon monoxide and volatile organic compound emissions limits of this rule pursuant to Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines subdivisions (f) – Monitoring, Testing, Recordkeeping and Reporting and (g) – Test Methods.

(B) Conduct yearly source test for particulate matter emissions according to SCAQMD Method 5.1 – Determination of Particulate Matter Emissions from Stationary Sources Using a Wet Impingement Train or SCAQMD Method 5.2 – Determination of Particulate Matter Emissions from Stationary Sources using Heated Probe and Filter to demonstrate compliance with the particulate matter emission limit. The yearly emission limit shall be defined as a period of twelve consecutive months determined on a rolling basis with a new twelve month period beginning on the first day of each calendar month.

(6) Ammonia Emissions Limits

(A) The owner or operator of each electric generating unit with catalytic control devices shall conducted quarterly source tests to demonstrate compliance with the ammonia emission limit according to SCAQMD Method 207.1 – Determination of Ammonia Emissions from Stationary Sources during the first twelve months of operation of the catalytic control device and annually thereafter if four consecutive source tests demonstrate compliance with the ammonia emission limit.

(B) In lieu of complying with paragraph (e)(6)(A), the owner or operator of each electric generating unit may utilize ammonia CEMS certified under an approved SCAQMD protocol to demonstrate compliance with the ammonia emission limit .

(7) Operating Log

The owner or operator of each electric generating unit shall maintain records, in a manner approved by the SCAQMD, in an operating log on a daily basis, for the following parameter(s) or item(s):

(A) Time and duration of start-ups and shutdowns;

(B) Total hours of operation;

(C) Quantity of fuel;

(D) Cumulative hours of operation to date for the calendar year;

(E) Megawatt hours of electricity produced; and

(F) Net megawatt hours electricity produced.

(f) Use of Liquid Petroleum Fuel

(1) Force Majeure Natural Gas Curtailment

The ~~District-wide daily limits on emissions rate and emissions cap specified in paragraphs (c)(1), (c)(2), and (c)(3)~~ NO_x emissions limits specified in subdivision (d) shall not apply to an electric ~~power~~ generating ~~system~~ unit or electricity generating facility on days of force majeure natural gas curtailment when the use of liquid petroleum fuel is required, provided that:

(A) Within 15 days of each occurrence, the owner or operator of each ~~boiler~~ electricity generating facility submits an affidavit signed by a corporate officer affirming that liquid petroleum fuel was burned due to force majeure natural gas curtailment; and

~~(B) Each boiler, when it burns natural gas exclusively, meets the applicable unit-specific NO_x emission limit specified in subparagraph (d)(1)(C); and~~

(~~C~~B) Each~~ boiler~~ electric generating unit, when it burns liquid petroleum fuel ~~exclusively~~, emits ~~oxides of nitrogen~~NO_x at no more than ~~2 times ~~the applicable unit-specific NO_x emission limit specified in s~~ubparagraph (d)(1)(C)~~ the SCAQMD permit.~~; and~~

~~(D) Each boiler, when it burns a combination of liquid petroleum fuel and natural gas, emits oxides of nitrogen at no more than the prorated limit for that unit, obtained from the requirements specified in subparagraphs (f)(1)(B) and (f)(1)(C), and weighted by the flow rate and gross heating value of natural gas and liquid petroleum fuel, respectively. The calculation procedure in the "CEMS Requirement Document for Utility Boilers", dated July 19, 1991 shall be followed.~~

(2) Fuel Readiness Testing

~~A boiler may burn liquid petroleum fuel for up to 24 hours in any calendar year for fuel readiness testing provided that the emission limitation specified in subparagraph (f)(1)(C) is met. The unit specific NOx emission limit specified in subparagraph (d)(1)(C) shall not apply during this period.~~The NO_x emissions limits specified in subdivision (d) shall not apply to an electric generating unit during fuel readiness testing and the electric generating unit may burn liquid petroleum fuel, provided that:

(A) Fuel readiness testing does not exceed sixty minutes on one day per week;

(B) Each electric generating unit, when it burns liquid petroleum fuel, emits NO_x at no more than the applicable unit-specific NO_x emission limit specified in the SCAQMD permit;

(C) Fuel readiness testing shall only occur after the equipment has reached the emissions limits specified in paragraph (d)(1) while firing on natural gas and shall commence no later than sixty minutes after achieving emissions limits specified in paragraph (d)(1) while firing on natural gas; and

(D) Each readiness test shall commence with the equipment switching from natural gas to liquid petroleum fuel and conclude with the equipment switching from liquid petroleum fuel to natural gas.

(3) Source Testing

The NO_x emissions limits specified in subdivision (d) shall not apply to an electric generating unit when it burns liquid petroleum fuel during emissions source testing and the electric generating unit may burn liquid petroleum fuel for emissions source testing specified by SCAQMD rules, including initial certifications of Continuous Emissions Monitoring Systems (CEMS) and semi-

<ins>annual Relative Accuracy Test Audits (RATAs). RATA tests shall only be conducted concurrently with weekly readiness testing.</ins>

~~(g) Municipal Bubble Options~~

~~(1) Any electric power generating system may form a municipal bubble by linking with one or more electric power generating system(s), for the purposes of this rule, provided all of the following conditions are met:~~

~~(A) The municipal bubble does not include Southern California Edison; and~~

~~(B) The municipal bubble is formed for at least one year, or more; and~~

~~(C) An application for approval of the municipal bubble is submitted jointly by all affected municipal utilities to the Executive Officer, at least six months in advance; and~~

~~(D) Written approval of the application for the municipal bubble is obtained from the Executive Officer prior to utilization of any provision contained in subsection (g), Municipal Bubble Options.~~

~~(2) The application for a municipal bubble required in subparagraph (g)(1)(C) shall include, without being limited to:~~

~~(A) Proposed amendments to the compliance plans of all affected municipal utilities, as required to meet or exceed the municipal bubble emissions limitations specified in paragraph (g)(3); and~~

~~(B) Applications for change of permit conditions to adjust~~ $\cancel{NO_x}$ ~~emissions limits for each boiler, replacement unit and approved alternative or advanced combustion resource in the District, as required by the proposed amendments to the compliance plans; and~~

~~(C) Any other information required by the Executive Officer to evaluate compliance with the provisions of this rule.~~

~~The Executive Officer shall not approve the application for a municipal bubble unless it is demonstrated to the satisfaction of the Executive Officer that such action(s) will result in compliance with the municipal bubble emissions limitations specified in paragraph (g)(3) in an enforceable manner.~~

~~(3) Municipal bubble emissions limitations shall be derived from the District-wide daily limits on emissions rate and emissions cap specified in paragraphs (c)(2) and (c)(3), for each municipal utility, as follows:~~

~~(A) The District-wide daily limits on emissions rate in pounds of~~ $\cancel{NO_x}$ ~~per net megawatt-hours shall be the sum of the emissions rates of each participating utility, weighted by the maximum permitted capacity of each~~

~~utility as a fraction of the total permitted capacity in the municipal bubble, for the applicable time period; and~~

~~(B) The District-wide daily limits on emissions cap in pounds of NO_x per day shall be the sum of the emissions cap of all participating utilities, for the applicable time period, and beginning December 31, 1999, if Los Angeles Department of Water and Power is included in the municipal bubble; and~~

~~(4) An electric power generating system subject to a municipal bubble approved by the Executive Officer shall be exempt from the utility-specific requirements of paragraphs (c)(2) and (c)(3); and be subject to the municipal bubble emissions limitations specified in paragraph (g)(3) for the applicable time period.~~

~~(5) A violation of any municipal bubble emissions limitations required in paragraph (g)(4) shall constitute a violation for each permitted boiler and replacement unit, operating during the exceedance period, in the municipal bubble. This provision shall not apply to approved alternative or advanced combustion resources.~~

(~~h~~g) Exemptions

(1) Combined Cycle Gas Turbines

The owner or operator of a combined cycle gas turbine installed prior to [*Date of Adoption*] shall not be subject to paragraph (d)(1) for that combined cycle gas turbine, provided that:

(A) The SCAQMD permit as of [*Date of Adoption*] includes a condition limiting the NO_x concentration to 2.5 ppmv NO_x or less at 15% oxygen on a dry basis; and

(B) The NO_x and ammonia limits, averaging times, and start-up, shutdown, and tuning requirements specified on the SCAQMD permit as of [*Date of Adoption*] are retained.

(2) Once-Through-Cooling Electric Generating Units

The owner or operator of an electric generating unit subject to the Clean Water Act Section 316(b) shall not be subject to paragraph (d)(1) for that electric generating unit, provided that:

(A) The NO_x and ammonia limits, averaging times, and start-up, shutdown, and tuning requirements specified on the SCAQMD permit as of [*Date of* Adoption] are retained; and

(B) On or before January 1, 2023, the owner or operator notifies SCAQMD of the shutdown and retirement dates mandated by the Clean Water Act Section 316(b); and

(C) Within 3 months of approval of an extension to the compliance date mandated by the Clean Water Act Section 316(b) by the State Water Resources Control Board pursuant to 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, the owner or operator notifies SCAQMD of the extension.

(3) Diesel Internal Combustion Engines Located on Santa Catalina Island

The owner or operator of a diesel internal combustion engine located on Santa Catalina Island installed prior to [*Date of Adoption*] shall not be subject to paragraph (d)(4) for that diesel internal combustion engine provided that:

(A) The SCAQMD permit as of [*Date of Adoption*] includes a condition limiting the NO_x concentration to 51 ppmv NO_x or less at 15% oxygen on a dry basis; and

(B) The NO_x, ammonia, carbon monoxide, volatile organic compounds, and particulate matter limits, averaging times, and start-up, shutdown, and tuning requirements specified on the SCAQMD permit as of [*Date of Adoption*] are retained.

(4) Low-Use

(A) Gas Turbines

The owner or operator of a gas turbine installed prior to [*Date of Adoption*] shall not be subject to emissions limits specified under paragraph (d)(1) for that gas turbine, provided that the gas turbine:

(i) Maintains an annual capacity factor of less than twenty-five percent each calendar year;

(ii) Maintains an annual capacity factor of less than ten percent averaged over three consecutive calendar years on a rolling basis;

(iii) Retains the NO_x and ammonia limits, averaging times, and start-up, shutdown, and tuning requirements specified on the SCAQMD permit as of [*Date of Adoption*]; and

(iv) This exemption shall be a condition of the SCAQMD permit.

(B) Boilers

The owner or operator of a boiler installed prior to [*Date of Adoption*] shall not be subject to paragraph (d)(1) for that boiler, provided that the boiler:

(i) Maintains an annual capacity factor of less than two and one half percent each calendar year;

(ii) Maintains an annual capacity factor of less than one percent averaged over three consecutive calendar years on a rolling basis;

(iii) Retains the NO_x and ammonia limits, averaging times, and start-up, shutdown, and tuning requirements specified on the SCAQMD permit as of [*Date of Adoption*]; and

(iv) This exemption shall be a condition of the SCAQMD permit.

(C) Initial Requirement for Low-Use Exemption

The owner or operator of an electricity generating facility that elects the low-use exemption pursuant to subparagraph (g)(4)(A) or (g)(4)(B) for a boiler or gas turbine shall submit SCAQMD permit applications by July 1, 2022 for each electric generating unit requesting the change of SCAQMD permit conditions to incorporate the low-use exemption.

(D) Eligibility for Low-Use Exemption

Eligibility of the low-use exemption shall be determined annually for each electric generating unit and reported to the Executive Officer no later than March 1 following each reporting year.

(E) Exceedance of Low-Use Exemption

(i) If an electric generating unit with a low-use exemption pursuant to subparagraph (g)(4)(A) or (g)(4)(B) exceeds the annual or three year average annual capacity factor limit, the owner or operator of that electric generating unit is subject to issuance of a notice of violation.

(ii) If an electric generating unit with a low-use exemption pursuant to subparagraph (g)(4)(A) or (g)(4)(B) exceeds the annual or three year average annual capacity factor limit, the owner or operator of that electric generating shall:

(A) Submit complete SCAQMD permit applications to repower, retrofit, or retire that electric generating unit within six months from the date of reported exceedance of subparagraph (g)(4)(A) or (g)(4)(B);

(B) Submit a CEMS Plan within six months from the date of complete SCAQMD permit application submittal pursuant to subclause (g)(4)(E)(ii)(A); and

(C) Not operate that electric generating unit in a manner that exceeds the emissions limits listed in Table I after two years from the date of the reported exceedance of subparagraph (g)(4)(A) or (g)(4)(B).

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

~~(1) Notwithstanding the provisions of paragraphs (c)(1) or (c)(2), Southern California Edison or Los Angeles Department of Water and Power may operate its electric power generating system if both the following District-wide daily limits on emissions rate and emissions cap are met:~~

	~~District-Wide Daily Limits Lb NOx/Net Megawatt (MW) Hr~~	~~Lb-NOx Per Day~~
~~Southern California Edison~~	~~0.25~~	~~5,360~~
~~Los Angeles Department of Water and Power~~	~~0.25~~	~~2,960~~

~~(2) Notwithstanding the provisions of paragraphs (c)(1), (c)(2), or (c)(3), an electric power generating system may be operated for no more than 10 calendar days in any calendar year if all the following conditions are met:~~

~~(A) Both the following District-wide daily limits on emissions rate and emissions cap are met:~~

	~~District-Wide Daily Limits Lb NOx/Net Megawatt (MW) Hr~~	~~Lb-NOx Per Day~~
~~Southern California Edison~~	~~0.25~~	~~20,100~~
~~Los Angeles Department of Water and Power~~	~~0.25~~	~~11,100~~
~~Burbank~~	~~0.25~~	~~870~~
~~Glendale~~	~~0.25~~	~~580~~
~~Pasadena~~	~~0.25~~	~~1,350;~~

~~and~~

~~(B) The electric generating system owner/operator has taken all possible steps to comply with paragraphs (c)(1), (c)(2) and (c)(3), including the interruption of non-firm load.~~

~~(C) The exemption is not required as a result of operator error, neglect, or improper operating or maintenance procedures;~~

~~(D) Steps are immediately taken to correct the condition;~~

~~(E) The electric power generating system owner/operator reports to the District the need for the exemption within one hour of the occurrence or~~

~~within one hour of the time said operator knew or reasonably should have known of the occurrence;~~

~~(F) No later than one week after each event the owner/operator submits a written report to the District including but not limited to:~~

~~(i) A statement that the situation has been corrected, together with the date of correction and proof of compliance;~~

~~(ii) A specific statement of the reason(s) or cause(s) for the exemption sufficient to enable the Executive Officer to determine whether the occurrence was in accordance with the criteria set forth in subparagraphs (h)(2)(B) and (h)(2)(C) of this rule;~~

~~(iii) A description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future.~~

~~**FOR REFERENCE PURPOSES ONLY:**~~ ~~**(Amended July 19, 1991)**~~

~~CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS) REQUIREMENTS DOCUMENT FOR UTILITY BOILERS~~

~~This document specifies requirements under Rule 1135 for continuous emission monitoring systems. Other District rules and permit conditions may require measurements, calculations, and reporting in addition to those indicated in this document.~~

~~1. REQUIREMENTS~~

~~1.1 The owner or operator of each boiler, unit, and approved alternative or advanced combustion resourceshall install, calibrate, maintain, and operate an approved CEMS, and record the output of the system, for measuring the following:~~

~~a. Nitrogen oxides emissions (in units of ppmv) discharged to the atmosphere from each boiler, unit, and approved alternative or advanced combustion resource.~~

~~b. Oxygen concentration, at each location where nitrogen oxides are monitored.~~

~~c. Stack gas volumetric flow rate. An in-stack flow meter may be used to determine mass emission rates to the atmosphere from each boiler, unit, and approved alternative or advanced combustion resource, except:~~

~~(i) when more than one boiler or resource vents to the atmosphere through a single stack, or~~

~~(ii) during periods of low flow rates when the flow rate is no longer within the applicable range of the in-stack flow meter.~~

~~d. Heat input rate when needed by the CEMS to determine the stack gas volumetric flow rate, or to determine applicable prorated emission limits during periods when the boiler, unit, or approved alternative or advanced combustion resource is firing on both gaseous and liquid fuels. The owner or operator shall include in the CEMS calculations the~~ F_d ~~factors listed in 40 CFR Part 60, Appendix A, Method 19, Table 19-1. The owner or operator shall submit data to develop~~ F_d ~~factors when alternative fuels are fired and obtain the approval of the Executive Officer for use of the~~ F_d ~~factors before firing any alternative fuels.~~

~~e. Net MWH of electricity produced at each affected boiler, unit, or approved alternative or advanced combustion resource.~~

~~The owner or operator shall also provide any other data necessary for calculating air contaminant emission rates as determined by the Executive Officer.~~

~~2. MONITORING SYSTEMS~~

~~2.1 All CEMS at each affected boiler, unit, or approved alternative or advanced combustion resource shall, at a minimum, generate and record the following data points once per minute:~~

~~a. Nitrogen oxide concentration in the stack in units of ppmv.~~

~~b. Oxygen concentration in the stack in units of percent.~~

~~c. Volumetric flow rate of stack gases in units of dry standard cubic feet per minute (DSCFM). For Rule 1135 standard gas conditions are defined as temperature at 68°F and one atmosphere of pressure.~~

~~d. Fuel flow rates in units of standard cubic feet per minute (SCFM) for gaseous fuels or pounds per minute (lb/min) for liquid fuels if EPA Method 19 is used to calculate the stack gas volumetric flow rate.~~

~~e. Nitrogen oxide emission rate in units of lb/minute. The nitrogen oxide emission rate is calculated according to the following:~~

$$\cancel{e_i = a_i \times c_i \times 1.195 \times 10^{-7}}$$

~~where e_i = The emission rate of nitrogen oxides in pounds per minute measured every minute,~~

~~a_i = The stack gas concentration of nitrogen oxides measured each minute (ppmv),~~

~~c_i = The stack gas volumetric flow rate measured each minute (DSCFM).~~

~~When the CEMS uses the heat input rate to determine the nitrogen oxides emission rates, the CEMS will use the following equation to calculate the emission rate of nitrogen oxides:~~

$$\cancel{e_i = a_i \times [20.9/(20.9 - b_i)] \times 1.195 \times 10^{-7} \times \sum_{i=1}^{r} (F_{di} \times d_i \times V_i)}$$

~~where e_i = The emission rate of nitrogen oxides in pounds per minute measured every minute,~~

~~a_i = The stack gas concentration of nitrogen oxides measured each minute (ppmv) on a dry basis,~~

~~b_i = The stack gas concentrations of oxygen measured every minute~~

~~r = The number of different types of fuel,~~

~~F_{di} = The dry F factor for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (DSCF/10^6 BTU),~~

~~d_i = The fuel flow rate for each type of fuel measured every minute,~~

~~V_i = The higher heating value of the fuel for each type of fuel.~~

~~The product (d_i x V_i) must have units of millions of BTU per minute (10^6 BTU/min).~~

~~f. During any one minute period when the net MW output of the replacement unit exceeds the permitted net MW capacity of the replaced boiler, the data points e_i and f_i (defined in Paragraph 2.2) must be recalculated by multiplying by the following factor:~~

$$\cancel{(MW_p/MW_r)}$$

~~where MW_p = Net MW output capacity of the replaced boiler,~~

~~and MW_r = Net MW output during the one minute period~~

~~= f_i x 60~~

~~Record the uncorrected and corrected values of e_i and f_i. Calculate and record the data points E, F, G, and H, the hourly lb NO_x/net MWH of electricity produced, and the daily lb NO_x/net MWH of electricity produced using first the uncorrected and corrected e_i and f_i values and using then the corrected e_i and f_i values.~~

~~g. Net MWH of electricity produced. The net MWH are defined as:~~

$$\cancel{\text{net MWH} = VIt \cos ø / 10^6}$$

~~where V = Voltage to the power grid (Volt),~~
~~I = Current to the power grid (Ampere),~~
~~cos ø = Power factor,~~
~~and ø = Phase angle.~~
~~t = Time (hr) = 1/60 hr,~~

~~The above equation is only a definition of MWH and a meter which measures MWH directly may be used. The voltage, current, power factor, and time do not need to be measured separately.~~

~~net MWH = Gross MWH - Auxiliary MWH~~

~~h. CEMS status. The following codes shall be used to report the CEMS status:~~

~~0 - Collecting valid data,~~
~~1 - In calibration,~~
~~2 - Off line,~~
~~3 - Tamper/security,~~
~~4 - Alternative data acquisition (see Paragraphs 2.7 and 2.8),~~
~~5 - Hot Standby,~~
~~6 - Out-of-control,~~
~~7 - Startup/shutdown.~~

~~2.2~~ ~~The hourly average stack gas concentrations of nitrogen oxides and oxygen, the stack gas volumetric flow rate, the fuel flow rate, emissions of nitrogen oxides, the net MWH of electricity produced, and the emissions rate of nitrogen oxides shall be calculated and recorded for each affected boiler, unit, or approved alternative or advanced combustion resource:~~

$$\cancel{A = \frac{\sum_{i=1}^{n} a_i}{n}}$$ ~~(for NO_x concentration)~~

$$\cancel{B = \frac{\sum_{i=1}^{n} b_i}{n}}$$ ~~(for O_2 concentration)~~

$$\cancel{C = \frac{\sum_{i=1}^{n} c_i}{n} \times 60}$$ ~~(for stack gas volumetric flow rate)~~

$$\cancel{D = \frac{\sum_{i=1}^{n} d_i}{n} \times 60}$$ ~~(for fuel flow rates)~~

~~Calculate D for each type of fuel firing separately.~~

$$\cancel{E = \frac{\sum_{i=1}^{n} e_i}{n} \times 60}$$ ~~(for NO_x emissions)~~

$$\cancel{\sum^{n} f_i}$$

$$\cancel{F = \frac{i=1}{n} \times 60} \qquad \text{~~(for net MWH)~~}$$

$$\cancel{P = E/F} \text{ (for } \cancel{NO_x} \text{ emissions rate)}$$

~~All concentrations and stack gas flow rates shall be made on a consistent wet or dry basis.~~

~~where~~ ~~A =~~ ~~The hourly average stack gas concentration of nitrogen oxides,~~

~~a_i =~~ ~~The stack gas concentrations of nitrogen oxides measured every minute,~~

~~B =~~ ~~The hourly average oxygen stack concentration,~~

~~b_i =~~ ~~The stack gas concentrations of oxygen measured every minute,~~

~~C =~~ ~~The hourly average stack gas flow rate,~~

~~c_i =~~ ~~The stack gas volumetric flow rates measured every minute,~~

~~D_i =~~ ~~The hourly average fuel flow rates, for each type of fuel,~~

~~d_i =~~ ~~The fuel flow rate for each type of fuel measured every minute,~~

~~E =~~ ~~The hourly average emission rates of nitrogen oxides,~~

~~e_i =~~ ~~The emissions of nitrogen oxides in pounds per minute measured every minute,~~

~~F =~~ ~~The hourly net MWH of electricity produced,~~

~~f_i =~~ ~~The net MWH of electricity produced measured every minute,~~

~~P =~~ ~~The emissions rate of nitrogen oxides in pounds per net MWH of electricity produced~~

~~n =~~ ~~Number of valid data points during the hour.~~

~~Indicate any hourly data where n <45.~~

~~2.3~~ ~~The average daily emissions of nitrogen oxides shall be calculated and recorded for each affected boiler, unit, or approved alternative or advanced combustion resource:~~

$$\cancel{G = \frac{\sum_{i=1}^{N} e_i}{N} \times M}$$

~~where~~ ~~G =~~ ~~The daily emissions of nitrogen oxides in units of lb/day,~~

~~M =~~ ~~Number of operating minutes during the day,~~

~~and~~ ~~N =~~ ~~Number of valid data points during the day.~~

~~Indicate any daily data where N <90 percent of M.~~

~~2.4~~ ~~The average daily net MWH of electricity produced shall be calculated and recorded for each affected boiler, unit, or approved alternative or advanced combustion resource~~:

$$\cancel{H = \frac{\sum_{i=1}^{N} f_i}{N} \times M}$$

~~where H = The daily net MWH of electricity produced during the day,~~

~~Indicate any daily data where N <90 percent of M.~~

~~2.5~~ ~~The hourly unit-specific emission limit shall be calculated and recorded when more than one fuel is burned during the hour:~~

$$\cancel{J = \frac{\sum_{i=1}^{t} (L_i \times D_i \times V_i)}{\sum_{i=1}^{t} (D_i \times V_i)}}$$

~~where J = Hourly unit-specific emission limit when more than one type of fuel is fired (lb~~ $\cancel{NO_x}$~~/net MWH of electricity produced)~~

$\cancel{L_i}$ ~~= Unit-specific emission limit for each type of fuel fired (lb~~ $\cancel{NO_x}$~~/net MWH of electricity produced)~~

$\cancel{V_i}$ ~~= Higher heating value of each type of fuel~~

~~The product~~ $\cancel{(D_i \times V_i)}$ ~~must have units of millions of BTU per hour~~ $\cancel{(10^6}$ ~~BTU/hour)~~

~~2.6~~ ~~The CEMS shall be operated and data recorded during all periods of operation of the affected boilers, units, and approved alternative or advanced combustion resources including periods of start-up, shutdown, malfunction or emergency conditions, except for CEMS breakdowns and repairs. Calibration data shall be recorded during zero and span calibration checks, and zero and span adjustments. For periods of hot standby the utilities may enter a default value for~~ $\cancel{NO_x}$ ~~emissions. Before using any default values the utilities must obtain the approval of the Executive Officer and must include in the CEMS applications or CEMS plans the estimates of~~ $\cancel{NO_x}$ ~~emissions, the~~ $\cancel{NO_x}$ ~~concentrations, the oxygen concentrations, and the fuel input rate or the stack gas volumetric flow rate during~~

~~hot standby conditions. The Executive Officer will approve only those emission values which he finds to correspond to hot standby conditions.~~

~~2.7~~ ~~When less than 90% of valid nitrogen oxides emission data are collected by the CEMS, emission rate data shall be obtained using District Methods 7.1 or 100.1 (for NO_x concentration in the stack gas) in conjunction with District Methods 1.1, 2.1, 3.1, and 4.1 or by using District Methods 7.1 or 100.1 in conjunction with District Method 3.1 and EPA Method 19. If the NO_x concentrations are less than 20 ppm, use Special District Method 7.1 (IC Alternative) or Modified District Method 100.1 for Low NO_x Concentrations. Descriptions of the last two methods can be found in Paragraphs 3.3.1 and 3.3.2 of the Relative Accuracy Test Procedure. For District Method 7.1 or Special District Method 7.1 (IC Alternative), a minimum of 12 samples, equally spaced over a one-hour period, shall be taken. Each sample shall represent the five-minute period in which it was taken.~~

~~2.8~~ ~~Load curves of NO_x emission rates or other alternative means of NO_x emission rate data generation may be used to obtain nitrogen oxides emission data, provided the utility has obtained the approval of the Executive Officer prior to using alternate means of NO_x emission rate data generation. The load curves and the alternate means of NO_x emission rate data generation mentioned in this paragraph shall not be used more than 72 hours per calendar month and may only be used if no CEMS data or reference method data gathered under paragraph 2.7 is available. Load curves may be used on units which have air pollution control devices for the control of nitrogen oxides emissions provided the utilities submit a complete list of operating conditions that characterize the permitted operation. The conditions must be specified in the compliance plans and permits which the rule requires. The process parameters specified in the conditions must be monitored by the CEMS.~~

~~2.9~~ ~~At each affected boiler, unit, or approved alternative or advanced combustion resource the number of valid data points (N) during the day shall be greater than 90 percent of the number operating minutes during the day in order to obtain a valid daily emission rate for nitrogen oxides and the daily net MWH of electricity produced. Valid data points are data points from the CEMS which meet the requirements of Paragraphs 2.18, 2.19, 2.19.1, 2.19.2, 2.19.2, 2.19.4, 2.19.5, 2.19.6, 2.19.7, 2.19.8, and 2.20 or which are obtained by the methods indicated in Paragraphs 2.7 and 2.8. The utility is deemed to be out of compliance with rule 1135 on a systemwide basis if one or more boilers, units, or approved alternative or advanced combustion resources do not comply with the 90 percent valid data requirement.~~

~~2.10~~ ~~Full scale span ranges for the NO_x analyzers at each unit shall be set on a unit-by-unit basis. The full scale span range of the NO_x analyzers shall be set so that all the data points gathered by the CEMS lie within 20-95 percent of the full-scale span range.~~

~~2.11~~ ~~The CEMS design shall allow determination of calibration drift at zero and high-level (90 to 100 percent of full scale) values. Alternative low-level and high-level span values may be allowed with the prior written approval of the Executive Officer.~~

~~2.12~~ ~~The volumetric flow measurement system shall meet a relative accuracy requirement of being less than or equal to 10 percent of the mean value of the reference method test data in units of DSCFM. Relative accuracy is calculated by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.~~

~~2.13 The emission rate measurement shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of lb/hr. Relative accuracy is calculated by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.~~

~~2.14 The portion of the CEMS which samples, conditions, analyzes, and records the nitrogen oxides and oxygen concentrations in the stack gas shall be certified according to the specifications in District Rule 218.~~

~~2.15 Each boiler, unit, and approved alternative or advanced combustion resource shall have test facilities which meet the "Guidelines for Construction of Sampling and Testing Facilities" in the District Source Test Manual. If an alternate location (not conforming to the criteria of eight duct diameters downstream and two diameters upstream from a flow disturbance) is used, the absence of flow disturbance and stratification shall be demonstrated using District Source Test Methods.~~

~~2.16 The CEMS sample line from the CEMS probe to the sample conditioning system shall be heated to maintain the sample temperature above the dew point of the sample.~~

~~2.17 The District shall reevaluate the monitoring systems at any affected boiler, unit, or approved alternative or advanced combustion resource, where changes to the basic process equipment or air pollution control equipment occur, to determine the proper full span range of the monitors. Any monitor system requiring change to its full span range in order to meet the criteria in Paragraph 2.10 shall be recertified according to all the specifications in Rule 218 including the relative accuracy tests, the calibration drift tests, and the calibration error tests. A new CEMS plan shall be submitted for each CEMS which is reevaluated.~~

~~2.18 Procedure 1 of 40 CFR Part 60, Appendix F is incorporated by reference for the nitrogen oxides and oxygen monitors. The quality assurance plans required by 40 CFR Part 60, Appendix F shall be submitted to the District for the approval of the Executive Officer before the CEMS is certified. The reference method tests are those methods in Section 3 (RELATIVE ACCURACY TEST METHODS) of this guideline. Any CEMS which is deemed out-of-control by 40 CFR Part 60, Appendix F shall be corrected, retested by the appropriate audit procedure, and restored to in-control within 24 hours after being deemed out-of-control. If the CEMS is not in-control at the end of the 24-hour period, the CEMS data shall be gathered using the methods in paragraphs 2.7 and 2.8 of these requirements. All data which is gathered in order to comply with 40 CFR Part 60, Appendix F shall be maintained for two years and be made available to the Executive Officer upon request. Any such data which is invalidated shall be identified and reasons provided for any data invalidation.~~

~~2.19 Each volumetric flow measurement system shall be audited at least once each calendar quarter. Successive audits shall occur no closer than two months. The audits shall be conducted as follows:~~

~~2.19.1 The Relative Accuracy Test Audit (RATA) shall be conducted at least once every four quarters. Conduct the RATA as described in Section 3 (RELATIVE ACCURACY TEST METHODS).~~

~~2.19.2 The Relative Accuracy Audit may be conducted three of four calendar quarters, but no more than three quarters in succession. To conduct an RAA, follow the procedure described in Section 3 (RELATIVE ACCURACY TEST METHODS) for the relative accuracy test, except that only three sets of measurement data are required.~~

~~2.19.3 Follow the equations described in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2 to calculate the relative accuracy for the RATA. The RATA shall be calculated in units of dry standard cubic feet per minute (DSCFM).~~

~~2.19.4 Follow this equation to calculate the accuracy for the RAA:~~

$$\cancel{A = \frac{F_m - F_a}{F_a} \times 100}$$

~~where A = Accuracy of the volumetric flow measurement system.~~

~~F_m = Average response of the volumetric flow measurement system in units of DSCFM.~~

~~F_a = Average reference method audit value in units of DSCFM.~~

~~2.19.5 If the relative accuracy using the RATA exceeds 20 percent of the mean reference method value, the CEMS shall be considered out-of-control. If the relative accuracy exceeds ±15 percent using the RAA, the CEMS shall be considered out-of-control. If the CEMS is out-of-control, take necessary corrective action to eliminate the problem. Following corrective action, audit the CEMS accuracy with an RAA or an RATA to determine if the CEMS is operating properly. An RATA shall be used following an out-of-control period resulting from an RATA. If the audit shows the CEMS to be out-of-control, the CEMS operator shall report the results of the audit showing the CEMS to be out-of-control, any subsequent audit showing the CEMS to remain out-of-control following corrective action, and the audit showing the CEMS to be operating within specifications following corrective action.~~

~~2.19.6 The beginning of the out-of-control period shall be the time corresponding to the completion of the sampling of the RAA or RATA. The end of the out-of-control period shall be the time corresponding to the completion of the sampling of the subsequent successful RAA or RATA.~~

~~2.19.7 During the period the CEMS is out-of-control, the CEMS data shall not be used in calculating emission compliance nor be counted towards meeting minimum data availability.~~

~~2.19.8~~ ~~Whenever out-of-control periods occur for two consecutive quarters, the owner or operator shall revise the quality control procedures contained in the quality assurance plans, or modify and replace the CEMS. If the CEMS is modified or replaced, the new CEMS shall be recertified by the Executive Officer.~~

~~2.20~~ ~~The nitrogen oxides emission rate (lb NO_x/hr) portion of the CEMS at each boiler, unit or approved alternative or advanced combustion resource shall have a relative accuracy of no greater than 20 percent of the mean value of the reference method test data in terms of lb NO_x/hr. This relative accuracy test shall be conducted during the certification test of each CEMS, and shall be conducted at least once every four quarters as an RATA for each CEMS. An RAA may be conducted three of four calendar quarters as described in Paragraph 2.19.1. The definition of an out-of-control CEMS is the same as Paragraph 2.19.5, except that the RAA shall exceed ±20 percent before the CEMS is considered out-of-control. The definition of out-of-control period is the same as Paragraph 2.19.6. The CEMS status during an out-of-control period is the same as Paragraph 2.19.7. The criteria for acceptable procedures is the same as Paragraph 2.19.8.~~

~~3. RELATIVE ACCURACY TEST METHODS~~

~~3.1~~ ~~Conduct the reference method (RM) tests in such a way that they will yield results representative of the emissions from the source and can be correlated to the CEMS data.~~

~~3.2~~ ~~Conduct a minimum of nine sets of all necessary reference method (RM) tests. Conduct each set within a period of 30 to 60 minutes.~~

~~3.3~~ ~~Unless the expected concentrations of NO_x are less than 20 ppm, District Methods 7.1 or 100.1 are the reference methods for NO_x concentrations.~~

~~3.4~~ ~~Use the Special District Method 7.1 (IC Alternative) or the Modified District Method 100.1 to determine NO_x stack gas concentrations of less than 20 ppm.~~

~~3.4.1~~ ~~Modified District Method 100.1 for Low NO_x Concentrations~~

~~District Method 100.1 may be used to measure low NO_x concentrations if the following additional quality control measures are taken on the reference method monitor:~~

~~a.~~ ~~Perform NO_2 system bias checks in addition to the regular system bias check in District Method 100.1. Use approximately 10 ppm NO_2 span gas for this system bias check. Perform these checks at the beginning, the middle, and the end of each test day. The checks made in the middle and the end of the test day must be made before emptying the condensate from the sampling system (if applicable).~~

~~b.~~ ~~Determine the NO_x to NO concentration readings during at least one test run.~~

c. ~~Determine the NO_2 to NO conversion efficiency by running a known NO_2 calibration gas (about 10 ppm) through the NO_2 convertor and comparing the calibrated monitor response to the NO_2 concentration.~~

~~d.~~ ~~The calibration error limits and the calibration gas specifications are the same as those in District Method 100.1. However, the tester may use calibration gas certified to an analytical accuracy of ±2 percent if calibration gases with analytical accuracies of ±1 percent are not available.~~

~~e.~~ ~~Conduct an NH_3 interference test if NH_3 is present. Use NH_3 calibration gas at 80-100 percent of the allowed NH_3 concentration.~~

~~f.~~ ~~Conduct Special District Method 7.1 (IC Alternative) tests simultaneously with the Modified District 100.1 tests during at least two runs. Collect at least six NO_x bulbs during each run. Take at least two field blanks each testing day.~~

~~3.5~~ ~~District Method 2.1 shall be used to determine the stack gas volumetric flow rate.~~

~~3.6~~ ~~For District Method 2.1, District Method 1.1 shall be used to select the sampling site and the number of traverse points.~~

~~3.7~~ ~~District Method 3.1 shall be used for diluent gas (O_2 or CO_2) concentration and stack gas density determination.~~

~~3.8~~ ~~District Method 4.1 shall be used for moisture determination of the stack gas.~~

~~3.9~~ ~~The NO_x emissions shall be determined by using the results of paragraph 3.3 or 3.4 along with the results of paragraphs 3.5, 3.6, 3.7, and 3.8.~~

~~3.10~~ ~~Suitable methods may be used to measure the net MWH produced at each boiler, unit, or approved alternative or advanced combustion resource provided the following conditions are met:~~

~~a.~~ ~~The owner or operator of each affected boiler, unit, or approved alternative or advanced combustion resource shall submit details of suitable methods to measure the net MWH of electricity produced of each boiler, unit, or approved alternative or advanced combustion resource. At a minimum, these details shall include a description of the principle of measurement and calculations used to calculate the net MWH of electricity produced, and the technique and procedures used to calibrate each net MWH measurement device. Each net MWH meter shall be calibrated against standards which are traceable to National Institute of Standards and Technology (NIST) standards or to a higher authority if no NIST standards exist. The calibration accuracy tolerance of each net MWH measurement device shall be ±0.5 percent of all measured values. The methods submitted to the District shall be subject to the approval of the Executive Officer before they are used to determine the net MWH of electricity produced.~~

~~b. Each net MWH measurement device shall be calibrated a minimum of once every six months.~~

4. REPORTING PROCEDURES

~~4.1 Interim Reporting Procedures~~

~~4.1.1 From July 19, 1991 until December 31, 1992, the owner or operator will be allowed to use an interim procedure for data reporting and storage. The owner or operator shall submit as part of the required CEMS plan, a plan for interim data reporting and storage. The plan shall be subject to the approval of the Executive Officer and shall, at a minimum, meet the requirements of Paragraphs 4.1.2, 4.1.3, and 4.1.4.~~

~~4.1.2 All the data required in Paragraphs 4.1.3 and 4.1.4 shall be available at an identified location to the Executive Officer, upon request. This location shall be subject to the approval of the Executive Officer.~~

~~4.1.3 For each affected boiler, unit, or approved alternative or advanced combustion resource the following information shall be provided to the Executive Officer:~~

~~a. Calendar dates covered in the reporting period~~.

~~b. Each daily emission rate (lb NO_x/day) and each hourly emission rate (lb NO_x/hour).~~

~~c. Identification of the boiler, unit, or approved alternative or advanced combustion resource operating days for which a sufficient number of valid data points has not been taken; reasons for not taking sufficient data; and a description of corrective action taken.~~

~~d. Identification of F_d factor for each type of fuel used for calculations and the type of fuel burned~~.

~~e. Identification of times when daily averages have been obtained by manual sampling methods.~~

~~f. Identification of times when daily averages have been obtained by alternate means of NO_x emission rate data generation.~~

~~g. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with the performance specifications in Rule 218.~~

~~h. Results of daily CEMS drift tests and quarterly accuracy assessments, as required under 40 CFR Part 60, Appendix F, Procedure 1.~~

~~i. Identification of the times when the pollutant concentration exceeded full span of the CEMS.~~

~~j. The daily net MWH of electricity produced.~~

~~k. The hourly unit-specific emission limit (lb NO_x/net MWH of electricity produced.~~

~~l. The hourly lb NO_x/net MWH of electricity produced.~~

~~4.1.4 The following information for the entire utility system shall be provided to the Executive officer on a monthly basis:~~

~~a. Calendar dates covered in the reporting period.~~

~~b. The sum of the daily emission rates (lb NO_x/day) from all affected boilers, units, and approved alternative or advanced combustion resources.~~

~~c. The sum of the net MWH of electricity produced from all affected boilers, units, and approved alternative or advanced combustion resources.~~

~~d. The systemwide daily NO_x emission rate (lb NO_x per net MWH of electricity produced) expressed as a ratio of the sum of the daily emission rates from all boilers, units, and approved alternative or advanced combustion resources divided by the sum of the net MWH produced from all affected boilers, units, and approved alternative or advanced combustion resources.~~

~~4.1.5 All data required by Paragraphs 2.1, 2.2, 2.3, 2.4, 2.5, 4.1.3, and 4.1.4 shall be recorded and transmitted to the District in a format specified by the Executive Officer.~~

~~4.2 Final Reporting Procedures~~

~~4.2.1 On and after January 1, 1993, the RTU installed at each location shall constitute the reporting requirements.~~

~~4.2.2 On and after January 1, 1993, all or part of the interim data storage systems shall remain as continuous backup systems.~~

~~4.2.3 An alternate backup data storage system may be implemented, upon request. The owner or operator shall submit an Alternate Backup Data Storage Plan for the approval of the Executive Officer.~~

~~5. INTERIM MEASUREMENT PROCEDURES~~

~~5.1 Until December 31, 1992, the requirements of Paragraphs 2.19, 2.19.1, 2.19.2, 2.19.3, 2.19.4, 2.19.5, 2.19.6, 2.19.7, 2.19.8,(volumetric flow rate audit methods) 3.5, 3.6, 3.7, 3.8, and 3.9 (relative accuracy test methods) will be waived until such time as the required source testing facilities meeting the requirements of Paragraph 2.14 have been installed. The owner or operator shall submit as a part of the required CEMS plan, construction plans and a schedule for the installation of each new testing facility. The plan shall be submitted for the approval of the Executive Officer prior to installation. Prior to the completion of the testing facility for each emission source, the owner or operator shall submit a test plan for flow rate relative accuracy testing. Within 30 days after completion of the testing facilities (or 30 days of initial start-up thereafter), the required relative accuracy tests shall be completed. Sixty days thereafter, the owner or operator shall meet the requirements of Paragraphs 2.19, 2.19.1, 2.19.2, 2.19.3, 2.19.4, 2.19.5, 2.19.6, 2.19.7, and 2.19.8 using the reference methods in Paragraphs 3.5, 3.6, 3.7, 3.8, and 3.9 for relative accuracy test methods.~~

~~5.2 From July 19, 1991 to December 31, 1992, the data recorded by the system approved for Paragraph 4.1 shall be the data of record to determine if the CEMS meets the required performance specifications.~~

~~5.3 After December 31, 1992, the backup data system shall be the data of record to determine if the CEMS meets the required performance specifications. The backup system and the RTU system shall produce identical data.~~

~~5.4 Each orifice used to measure the fuel gas flow rate shall be removed from the gas supply line for an inspection once every 15 months. The following items shall be subject to inspection:~~

~~a. Each orifice shall be visually inspected for any nicks, dents, corrosion, erosion, or any other signs of damage according to the orifice manufacturer's specifications.~~

~~b. The diameter of each orifice shall be measured using the method recommended by the orifice manufacturer.~~

~~c. The flatness of the orifice shall be checked according to the orifice manufacturer's instructions. The departure from flatness of an orifice plate shall not exceed 0.010 inch per inch of dam height (D-d/2) along any diameter. Here D is the inside pipe diameter and d is the orifice diameter at its narrowest constriction.~~

~~d. The pressure gauge or other device measuring pressure drop across the orifice shall be calibrated against a manometer, and shall be replaced if it deviates more than ±2 percent across the range.~~

~~e. The surface roughness shall be measured using the method recommended by the orifice manufacturer. The surface roughness of an orifice plate shall not exceed 50 microinches.~~

~~f. The upstream edge of the measuring orifice shall be square and sharp so that it will not show a beam of light when checked with an orifice gauge.~~

~~g. In centering orifice plates, the orifice shall be concentric with the inside of the meter tube or fitting. The concentricity shall be maintained within 3 percent of the inside diameter of the tube or fitting along all diameters.~~

~~h. Any other calibration tests specified by the orifice manufacturer shall be conducted at this time.~~

~~5.5 If an orifice fails to meet any of the manufacturer's specifications, it shall be replaced within two weeks.~~

~~6. ALTERNATIVE PROCEDURES~~

~~6.1 **Emission Stack Flow Rate Determination**~~

~~In the event that more than one boiler vents to a common stack, the alternative reference method for determining individual boiler flow rates shall be EPA Method 19. This method may be used for applicable boilers before and after the interim period mentioned in Section 4.1. The orifice plates used in every boiler vented to a common stack shall meet the requirements in Paragraph 5.4.~~

~~**7. COGENERATION SYSTEMS**~~

~~7.1 Cogeneration units must also measure and record the useful thermal energy along with the other measurements required in previous sections of this document. The measurements must meet the following conditions:~~

~~a. The owner or operator of each affected cogeneration unit must submit details of suitable methods to measure the useful thermal energy. At a minimum, these details shall include a description of all the measurement devices, including but not limited to flow meters, pressure measurement devices, and temperature measurement devices, the calculations used to calculate the useful thermal energy, and the technique and procedures used to calibrate each measurement device. Each measurement device shall be calibrated against standards which are traceable to NIST standards or to a higher authority if no NIST standards exist. The calibration accuracy tolerance of each measurement device shall be ± 1 per cent of all measured values. All measurement devices shall measure and record one data point each minute. The methods submitted to the District shall be subject to the approval of the Executive Officer before they are used for~~ $\cancel{NO_x}$ ~~emission deductions mentioned in (b)(2)(B).~~

~~b. Each measurement device shall be calibrated a minimum of once every six months.~~