DIVISION OF ENVIRONMENTAL QUALITY

DRAFT OPERATING AIR PERMIT

PERMIT NUMBER: 1717-AOP-R10

IS ISSUED TO:
Entergy Arkansas, LLC - Lake Catherine Plant
141 West County Line Road
Malvern, AR 72104
Hot Spring County
AFIN: 30-00011

PURSUANT TO THE RULES OF THE ARKANSAS OPERATING AIR PERMIT PROGRAM, 8 CAR PT. 42: THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

January 7, 2022 AND January 6, 2027

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Demetria Kimbrough
Deputy Director, Office of Air Quality

Date

Table of Contents

SECTION I: FACILITY INFORMATION 5
SECTION II: INTRODUCTION 6
Summary of Permit Activity 6
Prevention of Significant Deterioration 6
Pre-Construction Monitoring Analysis 7
Preliminary Impact Determination 7
Additional Impacts Analysis 11
Best Available Control Technology 12
Process Description 37
Rules and Regulations 40
Emission Summary 41
SECTION III: PERMIT HISTORY 46
SECTION IV: SPECIFIC CONDITIONS 48
Unit LC#4: SN-03 with Support Equipment 48
SN-03 48
Acid Rain Requirements (SN-03) 50
SN-10 53
NESHAP ZZZZ Requirements 54
Unit IPS-CT (SN-11 with Support Equipment) 56
SN-11, 14, 15, 16, 17, 18, 19, and 22 56
Acid Rain Requirements 67
NSPS KKKKa Requirements (SN-11) 69
NSPS TTTTa Requirements (SN-11) 84
SN-12 88
NSPS IIII Requirements (SN-12) 90
NESHAP ZZZZ Requirements (SN-12) 94
SN-13 95
NSPS IIII Requirements (SN-13) 97
NESHAP ZZZZ Requirements (SN-13) 99
SN-20, 21 100
SECTION V: COMPLIANCE PLAN AND SCHEDULE 101
SECTION VI: PLANTWIDE CONDITIONS 102
SECTION VII: INSIGNIFICANT ACTIVITIES 111
SECTION VIII: GENERAL PROVISIONS 113

Appendix A – Maximum Capacity Emission Rates
Appendix B – ADEQ CEMS Conditions
Appendix C – Acid Rain Program – Acid Rain Permit Application
Appendix D – Transport Rule (TR) Trading Program Title V Requirements
Appendix E – NSPS Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
Appendix F – NSPS Subpart KKKKa – *Standards of Performance for Stationary Combustion Turbines*
Appendix G – NSPS Subpart TTTTa – *Standards of Performance for Stationary Combustion Turbines*
Appendix H – NESHAP Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

List of Acronyms and Abbreviations

Ark. Code Ann.	Arkansas Code Annotated
AFIN	Arkansas DEQ Facility Identification Number
CAR	Code of Arkansas Rules
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
Hp	Horsepower
lb/hr	Pound Per Hour
NESHAP	National Emission Standards (for) Hazardous Air Pollutants
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter Equal To Or Smaller Than Ten Microns
$PM_{2.5}$	Particulate Matter Equal To Or Smaller Than 2.5 Microns
RICE	Reciprocating Internal Combustion Engine
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	Entergy Arkansas, LLC - Lake Catherine Plant
AFIN:	30-00011
PERMIT NUMBER:	1717-AOP-R10
FACILITY ADDRESS:	141 West County Line Road Malvern, AR 72104
MAILING ADDRESS:	141 West County Line Road Malvern, AR 72104
COUNTY:	Hot Spring County
CONTACT NAME:	Braxton Bennett
CONTACT POSITION:	Sr. Manager, Power Plant
TELEPHONE NUMBER:	(501) 609-4601
REVIEWING ENGINEER:	Bart Patton
UTM North South (Y):	Zone 15: 3810519.47 m
UTM East West (X):	Zone 15: 509102.29 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Entergy Arkansas, LLC – Lake Catherine Plant is a natural gas fired power generating station located at 141 West County Line Road in Malvern, Arkansas. The facility proposes to build a new natural gas-fired simple cycle Combustion Turbine (CT) Electric Generating Unit (EGU) at the existing Lake Catherine facility to replace the existing unit.

The project will consist of constructing a new Mitsubishi Model M501JAC simple cycle combustion turbine referred to as Ironwood Power Station Unit 5 (IPS). There will be additional sources due to IPS: SN-12, Emergency Standby Generator; SN-13, Diesel Emergency Fire Water Pump; SN-14, Natural Gas Condensate Tank 3; SN-15, Natural gas Condensate Tank 4; SN-16, Combustion Turbine Lube Oil Vent; SN-17, Natural Gas Fugitive Emissions; SN-18, Ammonia Fugitive Emissions; SN-19, Diesel Fugitive Emissions; SN-20 and 21, Emergency Generator Diesel Tank 1 and 2; and SN-22, Natural Gas Dewpoint Heater.

The permit was updated to use Code of Arkansas Rules (CAR) citations and current standard language and the latest Acid Rain permit. Vacated provisions (rule was amended in 2022) of NESHAP ZZZZ for SN-10 were removed. Emissions will be unchanged until the LC4 unit and its associated equipment have been removed, and IPS and its support equipment are operational.

Annual permitted emissions increased as follows: 84.56 tpy Ammonia, 12.35 tpy H_2SO_4.

Prevention of Significant Deterioration

This project is a PSD revision request to add IPS Unit #5 (IPS-CT), comprising a new simple-cycle natural-gas combustion turbine and its related support equipment, with the unit to start up only after the removal from service of existing LC Unit #4. As shown in the site-wide potential emissions summary below, under the federal NSR program the Lake Catherine project will be a major source that requires PSD permitting CO, VOC, PM_{10}, $PM_{2.5}$, SAM and GHG (expressed as CO_2e).

Regulated Pollutant	Post IPS Project Site-wide Potential Emissions (tons/yr)	Credible Reductions from LC4 Shutdown (tons/yr)	IPS Project Emission Changes (ton/yr)	Significant Emission Rates (ton/yr)	Subject to PSD Review?
NOx	352.51	-324.10	28.41	40	No
CO	227.40	-25.20	202.2	100	Yes
VOC	87.43	-5.77	81.66	40	Yes
PM_{10}	30.40	-7.98	22.42	15	Yes
$PM_{2.5}$	30.40	-7.98	22.42	10	Yes
SO_2	8.10	-0.65	7.45	40	No
H_2SO_4	12.35	0	12.35	7	Yes
GHG	687,151	-127,938	559,213	75,000	Yes

Pre-Construction Monitoring Analysis

Dispersion modeling was conducted to determine whether the project is exempt from the pre-construction ambient monitoring data gathering requirements.

Pollutant	Averaging Period	Maximum Predicted Concentration at each receptor (ug/m3)		Significant Monitoring Concentration	Monitoring Required?
CO	8-hr	1st H (of 5yrs)	16.69	575	N
PM_{10}	24-hr	1st H (of 5yrs)	0.75629	10	N

The predicted CO and PM_{10} concentrations are less than the significance level, so pre-construction monitoring data is not required for these pollutants.

There is no exemption of a $PM_{2.5}$ pre-construction monitoring analysis, so the facility proposes the use of existing ambient air monitoring data from a representative monitor to meet the $PM_{2.5}$ pre-construction monitoring data requirement. The representative monitor for $PM_{2.5}$ is the Hot Springs monitor, located in Garland County. In addition, since the proposed project will have net emission increases of NO_X greater than 100 tpy, the facility also proposes the use of existing ambient air monitoring data from a representative monitor to meet the O_3 pre-construction monitoring data requirement. The ozone monitor will be Caddo Valley located in Clark County.

Preliminary Impact Determination

Preliminary impact determination modeling was conducted for PSD-significant emissions of CO, PM_{10}, and $PM_{2.5}$ to determine whether a full impact modeling analysis is required for each pollutant and averaging period.

MERPS (Modeled Emission Rates for Precursors) analysis

The facility estimated ozone impacts using the MERP analysis to determine whether a full impact modeling analysis is required for this pollutant. The MERP results were used to determine whether the project-related impacts are greater than the SIL.

While the analysis is intended to be performed on the emission changes, the facility chose to use the PTE of the new equipment for the short-term precursor impacts for $PM_{2.5}$ and Ozone. This is the conservative approach as there is no reduction from the existing units that are being replaced.

Class II Analysis

- The annualized daily NO_X emissions are 1,072 TPY. The 1,000 TPY MERPs were selected for the 8-hour O_3 and 24-hour $PM_{2.5}$ calculations.
- The annualized SO_2 emissions are 50 TPY. The 500 TPY MERP was selected for the 24-hour $PM_{2.5}$ calculation.

- The annualized VOC emissions are 104 TPY. The 500 TPY MERP should be selected for the 8-hour O_3 calculations. However, no 500 TPY VOC value was available for 8-hour O_3. Therefore, the 1,000 TPY MERP was selected for the 8-hour O_3 calculation. This provides a more conservative O_3 impact estimate than selecting the 500 TPY "Low" MERP.
- The annual increase in NO_X emissions is 28.4 TPY. The 500 TPY MERP was selected for the annual $PM_{2.5}$ calculation.
- The annual increase in SO_2 emissions is 7.5 TPY. The 500 TPY MERP was selected for the annual $PM_{2.5}$ calculation.

Based on these values all predicted concentrations are presented below. These precursor impacts will be added to their respective modeled pollutants for the SIL analysis presented in the next section.

Analysis		Averaging Period	SIL		Precursor	Project Emissions TPY	MERP TPY	Project Emissions/ MERP	Precursor Impact Individual		Precursor Impact Total	
			ug/m3	ppm					ug/m3	ppm	ug/m3	ppm
Hypothetical Source CUS 13, Pulaski	Ozone	8-Hour	--	0.001	NOX	1077	540.1	1.9942		0.0019942		0.0020329
					VOC	104	2,688	0.03870		0.00003870		
	PM2.5	24-Hour	1.2	--	NOX	1077	5,416	0.1989	0.23868		0.27534	
					SO2	50	1,637	0.03055	0.03666			

Analysis		Averaging Period	SIL		Precursor	Project Emissions TPY	MERP TPY	Project Emissions/ MERP	Precursor Impact Individual		Precursor Impact Total	
			ug/m3	ppm					ug/m3	ppm	ug/m3	ppm
Hypothetical Source CUS 13, Pulaski	PM2.5	Annual	0.13	--	NOX	28.4	31,417	0.00090397	0.000117516	--	0000187614	--
					SO2	7.5	13,911	0.0005392	0.000070096			

Class I Analysis

- The daily annualized NO_X emission increases are 1,077 TPY. The 1,000 TPY MERP was selected for the 24-hour $PM_{2.5}$ calculation.
- The daily annualized SO_2 emission increases are 50 TPY. The 500 TPY MERP was selected for the 24-hour $PM_{2.5}$ calculation.
- The annual increase in NO_X emissions is 28.4 TPY. The 500 TPY MERP was selected for the annual $PM_{2.5}$ calculation.
- The annual increase in SO_2 emissions is 7.5 TPY. The 500 TPY MERP was selected for the annual $PM_{2.5}$ calculation.

Analysis		Averaging Period	Class I SIL ug/m3	Precursor	Project Emissions TPY	MERP TPY	Project Emissions/ MERP	Precursor Impact Individual ug/m3	Precursor Impact Total ug/m3
Hypothetical Source CUS 13, Pulaski	PM2.5	24-Hour	0.27	NOX	1077	1,814	0.5938	0.16033	0.17732
				SO2	50	794.7	0.06292	0.01699	

Analysis		Averaging Period	Class I SIL ug/m3	Precursor	Project Emissions TPY	MERP TPY	Project Emissions/ MERP	Precursor Impact Individual ug/m3	Precursor Impact Total ug/m3
Hypothetical Source CUS 13, Pulaski	PM2.5	Annual	0.03	NOX	28.4	11,584	0.0024517	0.000073551	0.00010672
				SO2	7.5	6,787	0.0011051	0.00003316	

Area of Significant Impact Analysis Results

The following are the predicted concentrations of the project emission increases.

Pollutant	Averaging Period	Maximum Predicted Concentration at each receptor (ug/m3)			Class II Significant Impact Level (ug/m3)
		Precursor	Modeled	Total	
CO	1-hour	-	223.16	223.16	2000
	8-hour	-	16.69	16.69	500
PM_{10}	24-hour	-	0.75629	0.75629	5
PM_{10} Increment	Annual	-	0.10015	0.10015	1
$PM_{2.5}$ Increment	24-hour	0.27534	0.75629	1.03163	1.2
	Annual	0.000187614	0.10015	0.10034	0.13
$PM_{2.5}$ NAAQS	24-hour	0.27534	0.6857	0.96104	1.2
	Annual	0.000187614	0.09417	0.09436	0.13
O_3	8-hour	2.033	-	2.033	1 ppb

The predicted CO, PM_{10}, and $PM_{2.5}$ concentrations are less than their respective SILs. Based on the results of the preliminary impact determination, full impact or PSD increment modeling analyses are not required for these pollutants. However, the predicted eight-hour O_3 concentration is greater than the respective SIL. Therefore, full impact modeling analysis is required for this pollutant and averaging period.

Full Impact Analysis for O_3

The predicted ground-level concentrations from the NAAQS modeling, the background concentrations for the project area, and the sum of the two values is summarized below. The total impacts are compared to the NAAQS.

Pollutant	Averaging Period	Maximum predicted concentration (MERPS)	Background Concentration	Total	NAAQS
O_3	8-hour	2.033 ppb	62 ppb	64.033 ppb	70 ppb

Class I PSD Increment Near Field Analysis

Modeling for Class I PSD Increment was conducted for proposed increases in emissions to determine whether full impact modeling is required. The predicted ground-level concentrations and Class I PSD SILs are summarized below.

Pollutant	Averaging Period	Maximum Predicted Concentration			Significant Impact Level
		Modeled Impact	Precursor Impact	Total	
PM_{10}	24-hour	0.05427	--	0.05427	0.3
	Annual	0.00085	--	0.00085	0.2
$PM_{2.5}$	24-hour	0.05427	0.17732	0.2316	0.27
	Annual	0.00085	0.00010672	0.00095672	0.03

The predicted PM_{10}, and $PM_{2.5}$, concentrations are less than their respective Class I PSD increment SILs. No additional modeling is required for these pollutants.

Additional Impacts Analysis

The PSD regulations at 40 CFR 52.21(o) require a PSD additional impacts analysis to demonstrate that emissions associated with this project will not cause or contribute to adverse impacts with respect to growth, visibility, and soils and vegetation. When evaluating PSD additional impacts, it is important to consider the more modern IPS will replace operations at the existing LC4. Entergy is legally obligated to sunset operations of LC4 by no later than December 31, 2027, and the power generated by IPS will replace the power currently being generated by LC4. Based on vendor testing and permit requirements, the new IPS EGU is expected to have significantly better air emissions performance than existing LC4, meaning for each unit of electrical power placed into the grid, lower air emissions are expected once the replacement is made. From this analysis, it can be surmised that replacing LC4 with IPS will result in improvements in air quality and other impacts in the local air shed. From this perspective, it can be concluded that the IPS project will not result in any additional PSD impacts.

The Growth Impacts analysis evaluates a project's potential impact on industrial, commercial, and residential growth in the surrounding area. Because IPS is a replacement facility for LC4, the IPS project is expected not to have any impact on industrial, commercial, and residential growth in the surrounding area.

The Soils and Vegetation Impacts analysis is required to evaluate a project's potential adverse impacts on soil and vegetation in the surrounding area. Again, because IPS is a lower emitting, replacement facility for LC4, the IPS project will not have any discernable adverse impacts on the surrounding area’s soil and vegetation.

Best Available Control Technology

For each emission unit that emits an NSR regulated pollutant that is subject to PSD review, a BACT demonstration is required as specified at 40 CFR 52.21(j). As shown in the site-wide potential emissions summary above, the Ironwood project will be a major source that requires PSD permitting for the NSR-regulated pollutants CO, VOC, PM_{10}, $PM_{2.5}$, SAM and GHG (expressed as CO_2e). Because the project does not trigger PSD review for the NSR-regulated pollutants NO_x and SO_2, no BACT demonstrations are required for these pollutants.

BACT Analysis for IPS-CT (Simple Cycle Gas Turbine): SN-11

The new IPS power generation equipment proposed for Lake Catherine includes a Mitsubishi Model M501JAC simple cycle Gas Turbine (CT). The BACT demonstration for the CT main stack is presented as follows for each NSR regulated pollutant emitted from IPS that requires PSD review.

CO BACT Analysis for IPS-CT

Carbon monoxide forms in combustion devices as a product of incomplete combustion. Production of CO results when there is a lack of oxygen and insufficient residence time at high enough temperatures to complete the final step in oxidation. Controlling these factors to decrease CO, however, also tends to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control may result in higher levels of CO emissions. Thus, a balance must be established, whereby the flame temperature, residence time and excess oxygen are set to achieve the lowest NO_x emission rate possible to comply with BACT while keeping CO emissions to an acceptable level.

Step 1: Identify Available Control Technologies

The two available CO control options for gas turbine installations include:
- Combustion Controls/Good Combustion Techniques and
- Catalytic Oxidation

CO combustion control performance (good combustion techniques) is a function of available oxygen, combustion temperature, turbulence, and residence time. Formation of CO is a result of incomplete combustion of the fuel. Adequate fuel residence time and high temperature in the combustion zone can ensure minimal CO formation. A properly designed combustion system is effective at limiting CO formation by maintaining the optimum combustion zone temperature and amount of excess oxygen. Unfortunately, the addition of excess air and maintenance of high combustion temperatures for control of CO emissions may lead to increased NOx emissions. Consequently, the typical practice is to design the combustion system such that CO emissions are reduced as much as possible without causing NO_x levels to significantly increase. The only add-on control device that is commercially available for controlling CO emissions from gas turbine installations is an oxidation catalyst. The catalyst lowers the activation energy necessary for CO to react with available oxygen in the exhaust to produce CO_2. Oxidation catalysts operate optimally at a temperature range of 500° to 700° F and can also reduce volatile organic compounds (VOC) emissions.

Step 2: Eliminate Technically Infeasible Options

The two available CO control technologies for gas turbine installations are both technically feasible. The facility is proposing to employ both CO control technologies for this gas turbine system.

Step 3: Rank Remaining Options by Control Effectiveness

The top CO control technology is identified as good combustion techniques along with an add-on catalytic oxidation. In conjunction, these two technologies will result in a flue gas CO concentration of 4.0 ppmvd CO at 15% O_2 (24-hr-average basis).

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the facility is proposing to accept the top CO control technology for simple cycle CT systems. Good combustion practices include proper CT design, performing recommended maintenance, and proper operation of the system to promote efficient combustion.

Step 5: Select BACT

There were five entries listed in the RBLC for simple cycle combustion turbines that listed either oxidation catalyst or oxidation catalyst in conjunction with good combustion practices as the BACT control method and those CO BACT limits ranged from 5 to 10 ppmvd @ 15% O_2. The remaining RBLC entries listed various combustion methodologies including good combustion practices, proper design, use of pipeline quality natural gas, and dry low NO_x burners and those BACT limits ranged from 4 to 36 ppmvd @ 15% O_2. The proposed BACT technology for CO emission control represents the "top" available and feasible CO control technology for simple cycle CT systems as reported in the RBLC.

The CT system will utilize good combustion techniques and an add-on catalytic oxidation control system. Good combustion practices include proper CT design, performing recommended maintenance, and proper operation of the system to promote efficient combustion. Use of these technologies will yield a vendor-guaranteed flue gas CO concentration of 4.0 ppmvd CO at 15% O_2 (24-hr-average basis) for normal operations. This CO BACT level applies only during routine operation of the combustion turbine. For CO BACT during combustion turbine startup, shutdown and tuning operations, CO BACT will consist of employing good engineering combustion practices and limiting the frequency of startup/shutdown events.

VOC BACT for IPS-CT

VOC is unburned and emitted from the stack when there is a lack of oxygen and insufficient residence time at high enough temperatures to complete the final step in oxidation.

Step 1: Identify Available Control Technologies
Like CO, there are two available VOC control options for gas turbine installations:

- Combustion Controls/Good Combustion Techniques
- Catalytic Oxidation Add-on Control Device.

Step 2: Eliminate Technically Infeasible Options

The two available VOC control technologies for gas turbine installations identified above are both technically feasible. The facility is proposing to employ both VOC control technologies for this gas turbine system.

Step 3: Rank Remaining Options by Control Effectiveness

The top VOC control technology is identified as good combustion techniques along with an add-on catalytic oxidation. In conjunction, these two technologies will result in a flue gas VOC concentration of 1.0 ppmvd at 15% O_2 (annual-average basis).

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the facility is proposing to accept the top VOC control technology for simple cycle CT systems.

Step 5: Select BACT

The simple cycle CT system will utilize good combustion techniques and a catalytic control system which will yield a vendor-guaranteed flue gas VOC concentration of 1.0 ppmvd VOC at 15% O_2 (annual-average basis). Good combustion practices include proper CT design performing recommended maintenance, and proper operation of the system to promote efficient combustion. Most of the equipment listed in the RBLC is said to utilize good combustion practices and several also use an add-on catalytic oxidation control system for BACT compliance. The RBLC determinations show a wide range of VOC emission limits with various averaging periods ranging from 1.0 ppmvd to 10.8 ppmvd. This VOC BACT level applies only during routine operation of the combustion turbine. For VOC BACT during combustion turbine startup, shutdown and tuning operations, VOC BACT will consist of employing good engineering combustion practices and limiting the frequency of startup/shutdown events.

PM_{10} and $PM_{2.5}$ BACT Analysis for IPS-CT

Particulate matter (PM) emissions, which include both PM_{10} and $PM_{2.5}$ emissions, from simple cycle gas turbine installations are the result of unburned trace constituents in the fuel, unburned hydrocarbons, and the inlet air supply that may contain dust particles. PM emissions can also result from the formation of sulfates and nitrates, which are formed when certain sulfur- and nitrogen-oxide compounds react with ammonia.

Step 1: Identify Available Control Technologies

The control technologies that can potentially be used to control PM emissions include:

- Fabric Filter (Baghouse),
- Electrostatic Precipitator (ESP),
- Use of Clean Gaseous Fuels (e.g., pipeline quality natural gas), and
- Good Combustion Practices.

Step 2: Eliminate Technically Infeasible Options

The two available add-on PM control technologies identified above, baghouses and ESPs, were determined not to be technically feasible. The concentration of PM from a natural gas turbine installation is low and the size of particles in the flue gas stream are very small. Due to the high volumetric flow rates and low particulate concentrations in the exhaust stream from the gas turbine installation, use of a baghouse or ESP is considered technically infeasible and are eliminated from further BACT consideration. There are no known existing natural gas fired gas turbine installations that utilize add-on PM control equipment.

Step 3: Rank Remaining Options by Control Effectiveness

The use of good combustion practices and clean gaseous fuels are both technically feasible options. The facility will utilize both options for $PM_{10}/PM_{2.5}$ BACT compliance.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the facility is proposing to accept the top control technology for simple cycle CT systems.

Step 5: Select BACT

PM BACT is proposed to be 0.0052 lb/MMBtu on an annual-average basis. The annualized PM emission rate is 21.19 lb/hr, and the maximum annualized CT firing rate on an HHV basis is 4,056 MMBtu/hr. The annual-average hourly PM performance is then calculated as 0.0052 lb PM/MMBtu.

Firing clean-burning pipeline natural gas emits small quantities of PM species (PM_{10} and $PM_{2.5}$) from the CT main stack. The use of a catalytic oxidation system results in additional PM emissions. The expected flue gas PM concentration from the stack will be diluted. The selected PM BACT is the use of low sulfur pipeline natural gas and good combustion practices such that PM emissions will be limited to 0.0052 lb PM/MMBtu (annual-average basis).

Good combustion practices include proper CT design, performing recommended maintenance, and proper operation of the system to promote efficient combustion. The equipment listed in the RBLC is said to utilize good combustion practices and the burning of clean fuel for BACT compliance. The RBLC determinations show a wide range of PM emission limits with various averaging periods ranging from 0.0019 lb/MMBtu to 0.0840 lb/MMBtu. It is difficult to directly compare PM emission rates from different simple cycle turbines for the following reasons:

- In combustion turbines, condensable PM is formed from sulfur compounds primarily through the conversion of SO_2 to SO_3, which then reacts with water vapor to form H_2SO_4. H_2SO_4 can then react with NH_3 to form ammonium sulfate. The assumption used for natural gas sulfur content for each air permit is not available in the RBLC summary. The Ironwood Unit 5 combustion turbine PM/PM_{10}/$PM_{2.5}$ emissions are based on a natural gas average sulfur content of 0.5 gr/100 scf which is higher than the Acid Rain default value for natural gas in 40 CFR Part 75, Appendix D, Table D-5 which is based on a sulfur content of 0.2 gr/100 scf.
- Different air permits also assume different SO_2 to SO_3 conversion efficiencies which occur in the turbine combustion, in the SCR and in the Oxidation catalyst. The Unit 5 application uses a conservative assumption of 100% conversion of SO_2 to SO_3. This assumption increases the PM emission rate.
- PM emissions will also vary depending on the specific turbine model, and the geographic location of the turbine.
- Some of the older RBLC entries may be listing filterable PM instead of total PM. The AP-42 Section 3.3, Table 3.1-2a filterable PM emission factor for natural gas fired combustion turbines is 0.0019 lb/MMBtu. The lowest PM listed in the RBLC for simple cycle combustion turbines is 0.0019 lb/MMBtu in 2014 which is equal to the AP-42 filterable emission factor. Even though the RBLC lists the 0.0019 lb/MMBtu BACT limit as total PM, it is likely filterable PM.

The majority of PM/PM_{10}/$PM_{2.5}$ BACT determinations in the RBLC for simple cycle turbines are in the 0.006 to 0.009 lb/MMBtu range, and the proposed Ironwood Unit 5 combustion turbine PM emission rate of 0.0052 lb/MMBtu is lower than that range. In additional there are no RBLC BACT determinations requiring anything other than good combustion practices and/or use of pipeline quality natural gas as the emission control method. Therefore, the proposed Ironwood Unit 5 combustion turbine PM/PM_{10}/$PM_{2.5}$ emission rate meets BACT requirements.

Sulfuric Acid Mist (SAM) BACT for IPS-CT

Emissions of SO_2 occur from the oxidation of sulfur in the gaseous fuel fired in the CT system. Most fuel sulfur is converted to SO_2. A portion of the SO_2 will be further converted to H_2SO_4, also referred to as Sulfuric Acid Mist (SAM), which will exit from the main stack (EPN: IPS-CT / SN-11).

Step 1: Identify Available Control Technologies

The two available control technologies to control SAM emissions include:

- Wet scrubbing of SAM
- Use of clean burning, low sulfur natural gas fuel.

Step 2: Eliminate Technically Infeasible Options

Because the sulfur content in pipeline natural gas is extremely low, the SAM concentration in the flue gas will be diluted. For this reason, wet scrubbing of SAM emissions is technically infeasible and is eliminated from BACT consideration. Wet scrubbing would generate an additional wastewater stream.

Step 3: Rank Remaining Options by Control Effectiveness
The only available and technically feasible SAM control technology is the use of clean-burning, low sulfur natural gas fuel.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the facility is proposing to accept the top control technology.

Step 5: Select BACT

The proposed BACT for SAM emissions includes minimizing the formation of SO_2 and H_2SO_4 by using pipeline-quality natural gas with sulfur content not exceeding 1.0 grains S/100 scf on a short-term basis and not exceeding 0.5 grains S/100 scf on an annual-average basis. By employing a thermally efficient simple cycle power generation system, the quantity of natural gas fuel required per unit of power output is minimized to the extent reasonably possible.

The RBLC determinations show a range of SO_2 emission limits from 0.5 grains S/100 scf to 12 grains S/100 scf. The RBLC determinations were evaluated and the proposed BACT technology for SAM emission control represents the “top” available and feasible control technology for simple cycle CT systems as reported in the RBLC.

GHG BACT for IPS-CT

For the CT system, GHG emissions will be released from the main stack (EPN: IPS-CT / SN-11) in the form of CO_2, methane (CH_4) and nitrous oxide (N_2O). The primary GHG is CO_2 and the combined GHGs are expressed as CO_2 equivalents (CO_2 e) using the procedure in the federal GHG reporting rule found at 40 CFR Part 98. EPA promulgated a new NSPS GHG regulation which impacts this installation. In the May 9, 2024, Federal Register, EPA published 40 CFR 60 Subpart TTTTa (NSPS TTTTa), which establishes GHG standards for Stationary Combustion Turbine Electric Generating Units built after May 23, 2023. NSPS TTTTa implements a phased-in GHG control approach for base load units. However, a phased-in approach is not used in NSPS TTTTa for peaking units like the proposed IPS-CT EGU. The new regulation focuses only on CO_2 emissions and not any other GHG constituents. The new Ironwood CT (EPN: IPS-CT / SN-11) will be classified either as an Intermediate Load Combustion Turbine or a Low Load Combustion Turbine under NSPS TTTTa depending on electricity demand. NSPS TTTTa allows peaking combustion turbines to switch between intermediate load and low load status based on the actual electricity directed to the grid (i.e., the actual annual capacity factor). GHG BACT is proposed to be compliance with NSPS TTTTa. This means that the GHG BACT level of control will depend on whether the gas turbine is operating in low-load mode or intermediate-load mode. When the gas turbine is operating in an intermediate-load mode, NSPS TTTTa requires a CO_2 performance level of ≤ 1,170 lb CO_2 e/MWh of gross energy output on a 12-operating month average. For intermediate load operations, the new IPS EGU is projected to initially to have a compliant actual CO_2 performance level of 1,056 lb CO_2/MWh of gross energy output. When the gas turbine is operating in a low-load mode, NSPS TTTTa requires a CO_2 performance level of less than or equal to 120 lb CO_2/MMBtu-HHV of heat input. For low operations, the new IPS CT is projected to have a CO_2 performance level of 118.8 lb CO_2/MMBtu-HHV of heat input.

Step 1: Identify Available Control Technologies

The available control technologies to lower GHG emissions from CT installations include:

- Carbon Capture and Sequestration (CCS)
- Combustion of fuel containing hydrogen,
- Operating a system that has relatively high thermal efficiency with relatively low-carbon natural gas fuel.

Step 2: Eliminate Technically Infeasible Options

Research has been performed by the U.S. Department of Energy and others to limit GHG emissions from gas turbine units by employing CCS. In a CCS system, CO_2 emissions are captured, scrubbed, condensed, and routed via pipeline to an underground formation where the CO_2 is stored indefinitely (sequestered). Currently, CCS is not readily available in a commercial sense for the simple cycle system being proposed. Once CO_2 is separated from the flue gases, it must be transported to a suitable sequestration or storage facility. Storage opportunities typically would include disposing of the CO_2 in a Class 2 well used for enhanced oil recovery or disposing of the CO_2 in a Class 6 well which is used to inject CO_2 into deep rock formations as part of a process called Geologic Sequestration. Using CO_2 for Enhanced Oil Recovery is unstable because the demand for the CO_2 fluctuates significantly depending on the price of oil and natural gas. Therefore, it is not a reliable means for disposing of CO_2. To date, there are no permitted Class 6 Carbon Sequestration wells permitted in the State of Arkansas. The IPS simple cycle system is being designed such that a CCS retrofit could be accommodated in the future.

The installation of carbon capture for the control of greenhouse gas emissions is not technically feasible for simple cycle combustion turbines used in peaking service for the following reasons:

- A carbon capture unit cannot cycle up and down in the same time frames as peaking simple cycle combustion turbines. The combustion turbine proposed in this application will be used for peaking service and will have the ability to startup within a 32-minute window in response to electricity demand. A carbon capture system would typically require multiple hours to startup. Since operation of peaking units is on a demand basis, coordinating operation of a carbon capture unit with peaking combustion turbines would be impractical to implement as the peaking units may startup and shutdown before the carbon capture unit has completely started up.
- The first step in a carbon capture system is to use quenching water to cool the combustion turbine exhaust to approximately 150°F before entering the amine scrubber. While the typical exhaust temperature of a combined cycle combustion turbine is approximately 200°F, the exhaust temperature of simple cycle combustion turbine with SCR is typically 800°F. The quench water flow for a simple cycle combustion turbine would be impractical to implement. Additionally, installation of a carbon capture system would require the addition of an extremely large cooling tower which would fundamentally redefine the emission source that is being authorized.
- In the regenerator step of a carbon capture system, CO_2"rich" solvent from the amine scrubber is heated with process steam to liberate the CO_2 and leave reusable solvent behind. There is no steam source associated with a simple cycle turbine. Installation of a carbon capture system would require a source of steam such as a natural gas fired auxiliary boiler which would fundamentally redefine the emission source that is being authorized. The use of hydrogen as a fuel reduces CO_2 emissions because the product of hydrogen combustion is water. Studies by CT manufacturers indicate that with current CT technology, the quantity of hydrogen fuel a CT can accommodate is approximately 30%. The remaining balance of the fuel fired must be natural gas. At the time the proposed CT installation commences, the infrastructure to even partially fire hydrogen fuel is not readily available (e.g., there is no hydrogen pipeline near the site to obtain hydrogen fuel). CCS and hydrogen combustion are not currently "available", as that term is used in the top-down BACT process, because of infrastructure limitations.

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining GHG control option at this juncture is building and operating a system that has relatively high thermal efficiency while burning relatively low-carbon natural gas fuel. The proposed IPS EGU will have a gross thermal efficiency of 38.4% - HHV basis. This thermal efficiency is consistent with the best performing peaking unit simple cycle gas turbines available in today's world marketplace. The facility is electing to implement the top available technology after eliminating unavailable and technically infeasible options.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the top control technology is being proposed.

Step 5: Select BACT

Employing a simple cycle CT system with a relatively high thermal efficiency that is fired by low carbon natural gas fuel is consistent with recent BACT determinations for simple cycle systems presented in RBLC. For CT intermediate load operating periods, GHG BACT will be the use of low-carbon natural gas fuel with an efficient power generation system with a GHG performance level of ≤ 1,170 lb CO_2e/MWh of gross power output as required by NSPS Subpart TTTTa. During CT low load operating periods, GHG BACT will be the use of low-carbon natural gas fuel with an efficient power generation system with a GHG performance level of ≤ 120 lb CO_2/MMBtu-HHV of heat input as required by NSPS TTTTa. The low and intermediate load CO_2 BACT performance levels are both based on a 12-operating month average as specified in Table 1 of NSPS TTTTa. The NSPS TTTTa CO_2 limits will represent GHG BACT for this installation and are lower than the emission limits presented in RBLC.

BACT for Diesel-fired Emergency Internal Combustion Engines, SN-12 and SN-13

The facility proposes to have two emergency diesel-fired IC engines as support units to the IPS. The engines will be limited to 500 hr/yr of operation or less in emergency and non-emergency operating modes due to the engines' emergency classification status. One emergency diesel-fired IC engine powers a 2,180 kW emergency standby generator (EPN: IPS-EMGEN / SN-12). The engine is a Mitsubishi Model S16R-Y2PTAW2-1 with a 2,923 BHP rating. The other emergency diesel-fired IC engine powers a 235 kW emergency fire water pump (EPN: IPS-FWP / SN-13). The engine is a John Deere Model 6068HFC48A with a 282 BHP rating. The engines will only fire ULSD with a maximum sulfur content of 15 ppmw. The emergency standby generator is a USEPA-certified Tier 2 engine, and the emergency fire water pump is a USEPA-certified Tier 3 engine.

<u>Diesel Engines CO BACT</u>

Step 1: Identify Available Control Technologies

The CO control technologies that are available include:

- Catalytic oxidation of CO and
- Good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII CO emission limits.

Step 2: Eliminate Technically Infeasible Options

Both options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

Catalytic oxidation provides the best control effectiveness, followed by use of an engine certified to meet applicable NSPS IIII CO emission limits.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

Although an add-on catalytic control system is technically feasible for the two subject emergency engines, the cost of controlling CO for this application is economically prohibitive. Total annual CO emissions from the two engines combined are very small. This is due to engine operations being limited to 500 hr/yr/engine. For both engines, as shown in the control equipment cost calculations, the annualized cost for controlling CO emissions using a catalytic oxidizer exceeds $100,000 per ton of CO controlled. For this reason, catalytic oxidation is rejected as BACT for CO.

Step 5: Select BACT

The proposed CO BACT for the emergency engines is a Tier 2 or Tier 3 engine CO performance level using engines certified to meet NSPS IIII CO emission limits. This corresponds to the CO limit for emergency service engines in 40 CFR 60 Subpart IIII, the NSPS for Compression Ignition Internal Combustion Engines. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII CO requirements for engines that maintain an emergency classification.

For the diesel-fired Emergency Standby Generator (EPN: IPS-EMGEN / SN-12), CO BACT is proposed as the Tier 2 CO performance level of 3.50 g CO/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump (EPN: IPS-FWP / SN-13) CO BACT is proposed as the Tier 3 CO performance level of 3.50 g CO/kWh for engines of this rating. For both engines this is more stringent than NSPS Subpart IIII requires.

Diesel Engine VOC BACT

Step 1: Identify Available Control Technologies

The VOC control technologies that are available include:

- Catalytic oxidation of VOC and
- Good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII VOC emission limits

Step 2: Eliminate Technically Infeasible Options

Both options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

Catalytic oxidation provides the best control effectiveness, followed by use of an engine certified to meet applicable NSPS IIII VOC emission limits.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

Although an add-on catalytic control system is technically feasible for the two subject emergency engines, the cost of controlling VOC for this application is economically prohibitive. Total annual VOC emissions from the two engines combined are very small. This is due to engine operations being limited to 500 hr/yr/engine. For both engines, the annualized cost for controlling VOC emissions using a catalytic oxidizer exceeds $100,000 per ton of VOC controlled. For this reason, catalytic oxidation is rejected as BACT for VOC.

Step 5: Select BACT

The proposed VOC BACT for the emergency engines is the use of Tier 2 or Tier 3-compliant engines. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII requirements for engines that maintain an emergency classification. For the diesel-fired Emergency Standby Generator (EPN: IPS-EMGEN / SN-12), VOC BACT is proposed as the manufacturer’s guaranteed VOC performance level of 0.56 g VOC/kWh. For the diesel-fired Emergency Fire Water Pump (EPN: IPS-FWP / SN-13) VOC BACT is proposed as the manufacturer’s VOC performance level of 0.11 g VOC/kWh.

Diesel Engine PM BACT

Step 1: Identify Available Control Technologies

The control technologies that can potentially be used to control PM emissions include:
- Fabric Filter (Baghouse);
- Electrostatic Precipitator (ESP);
- Good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII PM emission limits.

Step 2: Eliminate Technically Infeasible Options

Because operation of the two engines is so infrequent (< 100 hr/yr) and the PM concentration in the engine flue gas is so dilute, it is technically infeasible to use PM add-on control equipment such as a fabric filter or ESP. No other similar source in the RBLC data utilizes add-on PM emission control devices

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining option is employing good combustion practices using an IC engine that is certified to meet NSPS Subpart IIII PM emission limits. This becomes the top technology.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the top control technology is being accepted.

Step 5: Select BACT

The proposed PM BACT for the emergency engines is a Tier 2 or Tier 3 engine PM performance level using engines certified to meet NSPS IIII. This corresponds to the PM limit for emergency service engines in 40 CFR 60 Subpart IIII, the NSPS for Compression Ignition Internal Combustion Engines. Both engines will be subject to and will comply with all applicable NSPS Subpart IIII PM requirements for engines that maintain an emergency classification.

For the diesel-fired Emergency Standby Generator (EPN: IPS-EMGEN / SN-12), PM BACT is proposed as the Tier 2 PM performance level of 0.20 g PM/kWh for engines of this power rating. For the diesel-fired Emergency Fire Water Pump (EPN: IPS-FWP / SN-13) PM BACT is proposed as the Tier 3 PM performance level of 0.20 g PM/kWh for engines of this power rating.

Diesel Engines GHG BACT

Step 1: Identify Available Control Technologies

The GHG control technologies considered this case include:

- Carbon Capture and Sequestration (CCS)
- Good combustion practices and the use of engines that are certified to meet NSPS IIII emission limits, and the complying with NSPS IIII work practice requirements.

There are no known CCS applications commercially available for emergency diesel-fired IC engines. Therefore, CCS is rejected as BACT for this application.

Step 2: Eliminate Technically Infeasible Options

The use of CCS is neither available nor technically feasible for this application. This leaves the only remaining option, which is employing good combustion practices and using engines that are certified to meet NSPS IIII emission requirements.

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining option is the top technology for this application. This requires employing good combustion practices and the use of engines that are certified to meet NSPS IIII emission requirements.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required. The top control technology is being accepted.

Step 5: Select BACT

The proposed GHG BACT for both engines is the use of efficient NSPS IIII-compliant USEPA-certified Tier 2 and Tier 3 engines with a GHG emissions performance levels specified in Tables C-1 and C-2 of 40 CFR Part 98, the mandatory GHG reporting rule.

Natural Gas Dewpoint Heater BACT Analysis: SN-22

To prevent liquid water droplets from entering the CT and to enhance thermal efficiency, the natural gas fuel to the CT is indirectly heated in a small natural gas-fired dewpoint heater (EPN: IPS-NGDPHTR / SN-22) that has a rated firing rate of 5.01 MMBtu/hr-HHV. The small dewpoint heater will be permitted to operate continuously (8,760 hr/yr).

Dewpoint Heater CO BACT

Step 1: Identify Available Control Technologies

The CO control technologies that are available for this small gas-fired heater include:

- Oxidation catalysts
- Employing good combustion techniques with a manufacturer's guaranteed CO performance level.

Step 2: Eliminate Technically Infeasible Options

The use of add-on CO controls such as an Oxidation Catalyst Unit is not technically feasible for this small heater. The use of add-on CO controls for this application is therefore rejected as BACT.

Step 3: Rank Remaining Options by Control Effectiveness

The only available and technically feasible CO control technology remaining for this heater is employing good combustion techniques with a manufacturer's guaranteed burner CO performance level of 0.037 lb CO/MMBtu.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the top control technology is being accepted.

Step 5: Select BACT

CO BACT for this heater is proposed to be the use of good combustion practices to achieve a manufacturer's guaranteed CO performance level of 0.037 lb CO/MMBtu

Dewpoint Heater VOC BACT

Step 1: Identify Available Control Technologies

The VOC control technologies that are available for this small gas-fired heater include:

- Oxidation catalysts
- Employing good combustion techniques with a manufacturer's guaranteed VOC performance level.

Step 2: Eliminate Technically Infeasible Options

The use of add-on VOC controls such as an Oxidation Catalyst Unit is not technically feasible for this small heater. The use of add-on VOC controls for this application is therefore rejected as BACT.

Step 3: Rank Remaining Options by Control Effectiveness

The only available and technically feasible VOC control technology remaining for this heater is employing good combustion techniques with a manufacturer's guaranteed burner VOC performance level of 0.008 lb VOC/MMBtu.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the top control technology will be utilized.

Step 5: Select BACT

The use of add-on VOC controls such as an oxidation catalyst system is not technically feasible for this small heater. VOC BACT for this heater is proposed to be the use of good combustion practices to achieve a manufacturer's guaranteed VOC performance level of 0.008 lb VOC/MMBtu.

Dewpoint Heater PM BACT

Step 1: Identify Available Control Technologies

The control technologies that can potentially be used to control PM10/PM2.5 (PM) emissions from this very small heater include:

- Fabric Filter (Baghouse);
- Electrostatic Precipitator (ESP); and
- Good combustion practices using clean low-sulfur pipeline natural gas as a fuel with a burner manufacturer's guarantee to have low PM emissions.

Step 2: Eliminate Technically Infeasible Options

Because the heater is very small and the PM concentration in the heater flue gas is so dilute, it is technically infeasible to use PM add-on control equipment such as a fabric filter or ESP. Further, there are no known commercial applications of add-on PM controls for natural gas fired heaters, so this control option is also not "available."

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining option is employing good combustion practices and by using clean natural gas as a fuel and with a burner manufacturer's guarantee to have low PM emissions. This becomes the top technology.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the top control technology is being utilized.

Step 5: Select BACT

$PM_{10}/PM_{2.5}$ BACT for this heater is proposed to be the use of low sulfur pipeline natural gas and good combustion practices to achieve a manufacturer's guaranteed PM performance level of 0.0048 lb PM/MMBtu.

Dewpoint Heater GHG BACT

Step 1: Identify Available Control Technologies

The GHG control technologies that are considered in this case include:

- Carbon Capture and Sequestration (CCS) and
- Good combustion practices use a thermally efficient heater that is fired by relatively low-carbon emitting natural gas fuel.

There are no known CCS applications commercially available for small natural gas-fired heaters. Therefore, CCS is rejected as BACT for this application.

Step 2: Eliminate Technically Infeasible Options

The use of CCS is neither available nor technically feasible for this application. This leaves the only remaining option, which is employing good combustion practices with a thermally efficient heater that is fired by relatively low-carbon-emitting natural gas fuel.

Step 3: Rank Remaining Options by Control Effectiveness

The only remaining option is the top technology for this application. This requires employing good combustion practices with a thermally efficient heater that is fired by relatively low-carbon-emitting natural gas fuel.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because the top control technology is being accepted.

Step 5: Select BACT

It is not technically feasible to use CCS technology in this application. The proposed GHG BACT for this small heater is using clean burning and efficient pipeline natural gas fuel and employing good combustion practices with GHG emissions performance levels specified in Tables C-1 and C-2 of 40 CFR 98, the mandatory GHG reporting rule.

BACT Analysis for Associated Storage Tanks: SN-14, SN-15, SN-20, SN-21

Entergy proposes to construct two small horizontal fixed-roof diesel storage tanks. Each tank provides ULSD fuel to the two emergency IC engines. The tank that will supply ULSD to the emergency generator will be a 99 bbl (4,150 gal) white, horizontal fixed-roof tank (EPN: IPS-TK1 / SN-20) mounted under the emergency generator frame. The tank that will supply ULSD to the emergency fire water pump will be a 12 bbl (500 gal) white, horizontal fixed-roof tank (EPN: IPS-TK2 / SN-21).

Entergy also proposes to construct two small horizontal fixed-roof tanks to store any natural gas condensate that may be present in the incoming natural gas fuel. Both tanks (EPNs: IPS-TK3 / SN-14 and IPS-TK4 / SN-15) have a volume of 400 gal and are equipped with an atmospheric vent.

<u>Storage Tanks VOC BACT</u>

Step 1: Identify Available Control Technologies

The VOC control technologies that are considered in this case include:
- Use of pressurized storage tanks;
- Use of an internal floating roof tank;
- Use of an external floating roof tank;
- Use of a fixed roof tank with the tank vent routed to and add-on VOC control device;
- Use of a fixed roof tank with a submerged fill pipe and an atmospheric vent. ULSD has a very low vapor pressure of 0.014 psia at storage conditions.

As a result, the combined annual VOC emission from the two diesel tanks will be very small. There are no known small diesel tanks in commercial practice that have controls that exceed use of fixed roof storage tank with an atmospheric vent. Likewise, even though the two condensate storage tanks will store material with a higher vapor pressure (RVP6), there are no known small condensate tanks in commercial practice of this type that have controls that exceed use of fixed roof storage tank with an atmospheric vent. All other tank control options are therefore not considered available or technically feasible for all four tanks. The proposed BACT for all four tanks is the use of white horizontal fixed-roof storage vessels and an atmospheric vent.

Step 2: Eliminate Technically Infeasible Options

The only available control technology remaining for ULSD and condensate storage is use of a fixed roof tank with a submerged fill pipe and an atmospheric vent.

Step 3: Rank Remaining Options by Control Effectiveness

The only available control technology remaining for ULSD and condensate storage is use of a fixed roof tank with a submerged fill pipe and an atmospheric vent

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because EAL is proposing to accept the top control technology.

Step 5: Select BACT

There are no known small diesel or condensate tanks in industrial practice that have controls other than fixed roof storage with an atmospheric vent. Therefore, the proposed BACT for all four tanks is the use of white horizontal fixed-roof storage vessels with a submerged fill pipe and an atmospheric vent.

Lube Oil System Vent BACT Analysis: SN-16

The new combustion turbine will be equipped with a dedicated lubrication system. Lubrication oil will be circulated through the turbine's machinery from the system's oil sump. The oil sump will be equipped with a vent that will be controlled by an oil mist eliminator. Emissions from the oil mist eliminator are based on lube oil replacement rates for similar units equipped with mist eliminators. Both VOCs and PM are expected to be emitted from for the combustion turbine lube oil vent (EPN: IPS-LOVCT / SN-16). The lube oil vent will be permitted to operate continuously (8,760 hr/yr).

<u>Lube Oil System VOC BACT</u>

Step 1: Identify Available Control Technologies

The VOC control technologies that are considered in this case include
- Atmospheric vent with a built-in mist eliminator
- Atmospheric vent with no controls.

Step 2: Eliminate Technically Infeasible Options

Both options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

The vent with a built-in mist eliminator represents the highest level of control.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because EAL is proposing to accept the top control technology.

Step 5: Select BACT

BACT is use of a mist eliminator is the only feasible VOC control technology for this small VOC source. Therefore, use of a mist eliminator is proposed as VOC BACT for the CT lube oil vent (EPN: IPS-LOVCT / SN-16)

Lube Oil System PM BACT

Step 1: Identify Available Control Technologies

The PM control technologies that are considered in this case include:

- Atmospheric vent with a built-in mist eliminator and
- Atmospheric vent with no controls.

Step 2: Eliminate Technically Infeasible Options

Both options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

The vent with a built-in mist eliminator represents the highest level of control.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

No evaluations of cost or other impacts are required because Entergy is proposing to accept the top control technology.

Step 5: Select BACT

BACT is use of a mist eliminator is the only feasible PM control technology for this small PM source. Therefore, use of a mist eliminator is proposed as $PM_{10}/PM_{2.5}$ BACT for the CT lube oil vent (EPN: IPS-LOVCT / SN-16).

Fugitive Emissions BACT Analysis: SN-17 and SN-19

The proposed new equipment at the Lake Catherine Power Station has the potential to leak VOC and GHG from equipment components. These components include valves, flanges and connectors, pumps, etc.

For the natural gas fugitives (EPN: IPS-NGFUG / SN-17), the VOC composition of the natural gas is only 1.58 wt%. Methane in natural gas is a GHG. This source also includes a small amount of GHG from sulfur hexafluoride (SF_6) insulation of circuit breakers. Fugitive GHG emissions for this source represent 0.01% of the facility-wide GHG annual emission rate.

For the diesel fugitives (EPN: IPS-DSLFUG / SN-19), annual fugitive VOC emissions are low due to the limited number of components in diesel service and that diesel is a low-emitting heavy liquid. There currently are no NSPS or NESHAP regulations which require a Leak Detection and Repair (LDAR) program for the fugitive sources (EPNs: IPS-NGFUG / SN-17 and IPS-DSLFUG / SN-19). If an LDAR program were implemented at Lake Catherine, it would monitor both VOC and GHG (methane) emissions.

<u>Fugitive Emissions VOC BACT</u>

Step 1: Identify Available Control Technologies
The available VOC control technologies for fugitive VOC emissions include:

- Implementing a traditional Leak Detection and Repair (LDAR) program using a portable hydrocarbon monitor and
- Implementing an Audio-Visual-Olfactory (AVO) LDAR program.

Step 2: Eliminate Technically Infeasible Options

Both LDAR program options identified above are technically feasible.

Step 3: Rank Remaining Options by Control Effectiveness

An LDAR program using a portable hydrocarbon detector is expected to have better control than an AVO LDAR program.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

Implementing a traditional LDAR program using a portable hydrocarbon detector is technically feasible, but for the minor amount of VOC control offered by an LDAR program, the VOC emission reduction achieved would be cost prohibitive. The cost for implementing a sitewide VOC LDAR program with a portable hydrocarbon detector would result in a control cost of over $30,000/ton VOC emissions reduced. For this reason, implementing an LDAR program is rejected as VOC BACT. The use of an AVO LDAR program becomes the top available option.

Step 5: Select BACT

Most fugitive VOC is emitted from natural gas components (EPN: IPS-NGFUG / SN-17). Because pipeline natural gas is odorized with a small quantity of mercaptan, an Audio-Visual-Olfactory (AVO) program to detect and repair leaks is technically feasible, highly effective and is the top remaining control option. For this reason, an AVO program is proposed for VOC BACT for the two affected fugitive sources (EPNs: IPS-NGFUG / SN-17 and IPS-DSLFUG / SN-19).

Fugitive Emissions GHG BACT

Step 1: Identify Available Control Technologies

The primary GHG fugitive pollutant will be methane from equipment in natural gas service (EPN: IPS-NGFUG / SN-17). This source also includes a small amount of GHG from sulfur hexafluoride (SF_6) insulation of circuit breakers. The available methane control technologies for fugitive methane emissions include:

- Implementing a traditional Leak Detection and Repair (LDAR) program using a portable hydrocarbon monitor
- Implementing an Audio-Visual-Olfactory (AVO) LDAR program.

Step 2: Eliminate Technically Infeasible Options

Both LDAR program options identified above are technically feasible

Step 3: Rank Remaining Options by Control Effectiveness

An LDAR program using a portable hydrocarbon detector is expected to have better control than an AVO LDAR program.

Step 4: Evaluate Most Effective Controls for Cost, Energy and Other Impacts

The GHG in question is methane in the natural gas emitted from IPS-NGFUG. An LDAR program that uses a portable hydrocarbon detector is technically feasible, but for the minor amount of GHG control offered by this LDAR program, the GHG emission reduction achieved would be cost prohibitive. The cost for implementing a sitewide GHG LDAR program would result in a control cost of over $578/ton CO_2e emissions reduced. For this reason, implementing an LDAR program is rejected as GHG BACT. The use of an AVO LDAR program becomes the top available option.

Step 5: Select BACT

Most fugitive methane is emitted from natural gas components (EPN: IPS-NGFUG / SN-17), plus a small amount of GHG from sulfur hexafluoride (SF_6) insulation of circuit breakers. Because pipeline natural gas is odorized with a small quantity of mercaptan, an Audio-Visual-Olfactory (AVO) program to detect and repair leaks is technically feasible, highly effective and is the top remaining control option. For this reason, an AVO program is proposed for GHG BACT for this fugitive emissions source.

BACT Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
SN-11	Gas Turbine	CO	Catalytic oxidation	4.0 ppmvd CO @ 15% O_2 (24-hr average basis)
		VOC	Catalytic oxidation	1.0 ppmvd CO @ 15% O_2 (annual average basis)
		$PM_{10}/PM_{2.5}$	Use of low sulfur pipeline natural gas and good combustion practices	0.0052 lb PM/MMBtu (annual-average basis)
		SAM	Use of pipeline-quality natural gas	1.0 grains S/100 scf (maximum hourly), 0.5 grains S/100 scf (annual-avg basis).
		GHG	Use of low-carbon natural gas fuel with an efficient power generation system	For intermediate load operating periods, GHG performance level of ≤ 1,170 lb CO2e/MWh of gross power output as required by During low-load operating periods, GHG performance level of ≤ 120 lb CO2/MMBtu-HHV of heat input
SN-12	Emergency Standby Generator	CO	Certified Tier 2 engine which meets the NSPS IIII emergency engine CO performance level of 3.5 g CO/kWh.	3.5 g CO/kWh

BACT Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		VOC	Meet the manufacturer's guaranteed VOC performance level of 0.56 g VOC/kWh.	0.56 g VOC/kWh
		$PM_{10}/PM_{2.5}$	Use of an USEPA-certified Tier 2 engine which meets the required NSPS subpart IIII emergency engine PM performance level of 0.2 g PM/kWh	0.20 g PM/kWh.
		GHG	Use of an efficient USEPA-certified Tier 2 engine which achieves a GHG performance levels specified in Tables C-1 and C-2 of 40 CFR 98.	-
SN-13	Emergency Fire Water Pump	CO	Use of a USEPA-certified Tier 3 engine which meets a CO performance level of 3.5 g CO/kWh.	3.5 g CO/kWh
		VOC	Meet the manufacturer's guaranteed VOC performance level of 0.11 g VOC/kWh.	0.11 g VOC/kWh
		$PM_{10}/PM_{2.5}$	Use of a USEPA-certified Tier 3 engine which achieves a PM performance level of 0.2 g PM/kWh.	0.20 g PM/kWh
		GHG	Use of an efficient USEPA-certified Tier 3 engine which achieves a GHG performance levels specified in Tables C-1 C-2 of 40 CFR 98.	-
SN-22	Natural Gas Dew Point Heater	CO	Use of good combustion practices	0.037 lb CO/MMBtu
		VOC	Use of good combustion practices	0.008 lb VOC/MMBtu
		$PM_{10}/PM_{2.5}$	Use of good combustion practices	0.0048 lb PM/MMBtu

BACT Summary				
Source	Description	Pollutant	Control Technology	BACT Limit
		GHG	Use of clean burning and efficient pipeline natural gas fuel and the employment of good combustion practices to achieve a GHG emissions performance levels prespecified in Tables C-1 and 2 of 40 CFR 98.	-
SN-14, SN-15, SN-20, and SN-21	Tanks – Diesel and Natural gas Condensate	VOC	Use of white, horizontal fixed-roof storage vessel with an atmospheric vent.	-
SN-16	Combustion Turbine Lube Oil Vent	VOC	Use of a mist eliminator to reduce emissions of oil droplets from the lube oil reservoir	-
		$PM_{10}/PM_{2.5}$		-
SN-17 and SN-19	Natural gas and Diesel Fugitives	VOC	Employ an audio-visual-olfactory program to detect and repair equipment component leaks.	-
		GHG		-

Process Description

Entergy Arkansas LLC (EAL) owns and operates a single-unit electric generating station located on Lake Catherine in Malvern, Hot Spring County, Arkansas. The site was in existence prior to 1972, before the Air Code and SIP were promulgated.

Unit #4 (Lake Catherine Unit #4, or LC4) is required to cease operation by December 31, 2027, pursuant to a Settlement Agreement between EAL, Sierra Club, and National Parks Conservation Association. Unit #5 (Ironwood Power Station #5, or IPS-CT) is being permitted with the issuance of Permit 1717-AOP-R10, with expected startup in 2029. The site will remain a single-unit electric generation station because IPS is not permitted to commence operation until LC4 is removed from service.

Lake Catherine Unit #4, SN-03 and 10

Electricity for sale is produced by the combustion of pipeline-quality natural gas in SN-03, a nominal 5,850 MMBtu/hr tangentially fired natural gas boiler. The boiler generates steam used to drive an electrical generator. SN-03 is the primary emission source located at the site. A diesel-fired emergency generator (SN-10) is located at the site, and various small emission sources exist which are listed in the insignificant activities list.

Ironwood Power Station Unit #5 (IPS-CT) Turbine and support equipment, SN-11, 16

The gross baseload generation capacity of the new simple cycle turbine will be approximately 456 MWe at the International Organization for Standardization (ISO) 3977 ambient conditions of 59 degrees Fahrenheit (°F), and 60% relative humidity. The proposed IPS will be fired exclusively with pipeline quality natural gas. Electricity for sale is produced by the combustion of pipeline-quality natural gas in SN-11 (IPSCT), a simple-cycle peaking-load combustion turbine.

The proposed emission controls for the gas turbine flue gas include an ammonia-based Selective Catalytic Reduction (SCR) system to reduce NOx emissions, and a catalytic oxidation unit to reduce CO and VOC emissions. The specified control levels of the SCR and catalytic oxidation systems result in the following combustion turbine flue gas pollutant concentrations:

- NOX 15 ppmvd @ 15% O2
- CO 4.0 ppmvd @ 15% O2
- VOC 1.0 ppmvd @ 15% O2

Emissions of GHG are limited by using natural gas as a fuel and installing a power generation system with, for a simple cycle peaking unit, a relatively high gross thermal efficiency of greater than 38% - HHV basis.

The new combustion turbine will be equipped with a dedicated lubrication system. Lubrication oil will be circulated through the turbine's machinery from the system's oil sump. The oil sump will be equipped with a vent that will be controlled by an oil mist eliminator. Emissions from the oil mist eliminator are based on lube oil replacement rates for similar units equipped with mist eliminators. Both VOCs and PM are expected to be emitted from for the combustion turbine lube oil vent (EPN: IPS-LOVCT / SN-16). The lube oil vent will be permitted to operate continuously (8,760 hr/yr).

Natural Gas System and Dewpoint Heater Operations, SN-22

Pipeline-quality natural gas will be delivered to the site via pipeline. It is metered and piped to the natural gas-fired combustion turbine (SN-11, IPS-CT). The natural gas fuel to the CT will be indirectly heated in a 5.01 MMBtu/hr natural gas-fired dewpoint heater (SN-22, IPSNGDPHTR), to keep the gas above the dewpoint temperature, making sure the fuel stays in the vapor phase between the heater and the combustion area. This is to prevent poor combustion and damage to the turbine.

Filtered ambient air is drawn into the compressor section of the combustion turbine generator (CTG). During periods of warm-to-hot ambient temperatures, the temperature of the inlet air to the CTG may be lowered using evaporative cooling to increase the mass air flow through the turbine and achieve maximum turbine power output.

Emergency Engines and Tanks, SN-12, 13, 14, 15, 20, and 21

The facility will have two emergency diesel-fired IC engines as support units to the IPS. The engines will be limited to 500 hr/yr of operation or less in emergency and non-emergency operating modes due to the engines' emergency classification status. One emergency diesel-fired IC engine powers a 2,180 kW emergency standby generator (EPN: IPS-EMGEN / SN-12). The engine is a Mitsubishi Model S16R-Y2PTAW2-1 with a 2,923 BHP rating.

The other emergency diesel-fired IC engine powers a 235 kW emergency fire water pump (EPN: IPS-FWP / SN-13). The engine is a John Deere Model 6068HFC48A with a 282 BHP rating. The engines will only fire ULSD with a maximum sulfur content of 15 ppmw. The emergency standby generator is a USEPA-certified Tier 2 engine, and the emergency fire water pump is a USEPA-certified Tier 3 engine.

Two small horizontal fixed-roof diesel storage tanks will be constructed to provide ULSD fuel to the two emergency IC engines. The tank that will supply ULSD to the emergency generator will be a 99 bbl (4,150 gal) white, horizontal fixed-roof tank (EPN: IPS-TK1 / SN-20) mounted under the emergency generator frame. The tank that will supply ULSD to the emergency fire water pump will be a 12 bbl (500 gal) white, horizontal fixed-roof tank (EPN: IPS-TK2 / SN-21).

Two small horizontal fixed-roof tanks will be constructed to store any natural gas condensate that may be present in the incoming natural gas fuel. Both tanks (EPNs: IPS-TK3 / SN-14 and IPS-TK4 / SN-15) have a volume of 400 gal and are equipped with an atmospheric vent.

Fugitive Emissions, SN-17, 18, and SN-19

The new equipment at the Lake Catherine Power Station for the IPS unit has the potential to leak VOC and GHG from equipment components. These components include valves, flanges and connectors, pumps, etc.

For the natural gas fugitives (EPN: IPS-NGFUG / SN-17), the VOC composition of the natural gas is only 1.58 wt%. Methane in natural gas is a GHG. This source also includes a small amount of GHG from sulfur hexafluoride (SF_6) insulation of circuit breakers. Fugitive GHG emissions for this source represent 0.01% of the facility-wide GHG annual emission rate.

For the ammonia fugitives (EPN: IPS-AMMFUG / SN-18), a 40,000-gallon pressurized storage tank for ammonia used in the catalytic reduction system is not expected to have any routine air emissions. Therefore, no emission point ID is assigned to the ammonia storage tank. However, potential fugitive emissions of ammonia come from piping components, such as valves, flanges, connectors, pumps, open-ended lines, and relief valves. These fugitives are very small compared to ammonia emissions from the catalytic reduction system and represent 0.005% of the facility-wide ammonia annual emission rate.

For the diesel fugitives (EPN: IPS-DSLFUG / SN-19), annual fugitive VOC emissions are low due to the limited number of components in diesel service and that diesel is a low-emitting heavy liquid. There currently are no NSPS or NESHAP regulations which require a Leak Detection and Repair (LDAR) program for the fugitive sources (EPNs: IPS-NGFUG / SN-17, IPS-AMMFUG / SN-18 and IPS-DSLFUG / SN-19). If an LDAR program were implemented at Lake Catherine, it would monitor both VOC and GHG (methane) emissions.

Rules and Regulations

The following table contains the rules and regulations applicable to this permit.

Rules and Regulations
Arkansas Air Pollution Control Code, 8 CAR pt. 40, effective March 14, 2016
Rules of the Arkansas Plan of Implementation for Air Pollution Control, 8 CAR pt. 41, effective May 6, 2022
Rules of the Arkansas Operating Air Permit Program, 8 CAR pt. 42, effective March 14, 2016
40 C.F.R. § 52.21 – *Prevention of Significant Deterioration of Air Quality*
40 C.F.R. § 60, Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 C.F.R. § 60, Subpart KKKKa – *Standards of Performance for Stationary Combustion Turbines*
40 C.F.R. § 60, Subpart TTTTa – *Standards of Performance for Stationary Combustion Turbines*
40 C.F.R. § 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
40 C.F.R. § 72 through 75, Acid Rain Program
40 C.F.R. § 97, Subpart BBBBB – *CSAPR* NO_x *Ozone Season Group 1 Trading Program*

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY: Highest of LC4 or IPS				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	45.0	195.3
		PM_{10}	44.9	195.2
		$PM_{2.5}$	See Note*	
		SO_2	11.9	18.7
		VOC	438.3	141.7
		CO	882.6	620.4
		NO_X	3,411.9	14,881.8
		Total HAPs	11.08	48.41
		CO_2e	N/A	687,153
		H_2SO_4	17.71	12.35
		Ammonia	60.54	84.56

*$PM_{2.5}$ limits are source specific, if required. Not all sources have $PM_{2.5}$ limits.
**HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

EMISSION SUMMARY: LC4 ONLY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	45.0	195.3
		PM_{10}	44.9	195.2
		$PM_{2.5}$	See Note*	
		SO_2	6.6	18.7
		VOC	32.8	141.7
		CO	145.4	620.4
		NO_X	3,411.9	14,881.8
		Total HAPs	11.08	48.41
SN-03	C4 Unit 4 Boiler (Natural Gas)	PM PM_{10} SO_2 VOC CO NO_x Total HAPs	44.5 44.5 3.6 32.2 140.4 3,393.0 11.05	194.8 194.8 15.4 141.0 615.0 14,861.4 48.38
SN-10	Emergency Diesel Generator	PM PM_{10} SO_2 VOC CO NO_x Total HAPs	0.5 0.4 3.0 0.6 5.0 18.9 0.03	0.5 0.4 3.3 0.6 5.4 20.4 0.03

EMISSION SUMMARY: IPS ONLY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	37.5	30.8
		PM_{10}	37.5	30.8
		$PM_{2.5}$	37.5	30.8
		SO_2	11.9	8.4
		VOC	438.3	88.2
		CO	882.6	227.7
		NO_X	281.1	352.7
		CO_2e	N/A	687,153
		H_2SO_4	17.71	12.35
		Ammonia	60.54	84.56
		Total HAPs	2.52	3.50
SN-11	Simple-Cycle Combustion Turbine Unit 5 (Natural Gas-Fired, 467 MWe, 4,119 MMBtu/hr max)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e H_2SO_4 Ammonia Total HAPs	36.1 36.1 36.1 11.6 427.7 863.6 248.1 N/A 17.71 60.33 2.46	30.1 30.1 30.1 8.1 86.2 222.0 344.1 683,187 12.35 84.19 3.43
SN-12	Emergency Standby Generator Engine (Diesel-Fired, 2,923 bhp, 22.09 MMBtu/hr max)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e Total HAPs	1.0 1.0 1.0 0.1 2.7 16.9 30.8 N/A 0.04	0.3 0.3 0.3 0.1 0.7 4.3 7.7 904 0.01

EMISSION SUMMARY: IPS ONLY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-13	Diesel Emergency Fire Water Pump (282 hp, diesel-fired, 1.89 MMBtu/hr)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e Total HAPs	0.2 0.2 0.2 0.1 0.1 1.9 2.1 N/A 0.01	0.1 0.1 0.1 0.1 0.1 0.5 0.6 78 0.01
SN-14	Natural Gas Condensate Tank #3	VOC	3.5	0.1
SN-15	Natural Gas Condensate Tank #4	VOC	3.5	0.1
SN-16	Combustion Turbine Lube Oil Vent	PM PM_{10} $PM_{2.5}$ VOC	0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.1
SN-17	Natural Gas Fugitive Emissions	VOC CO_2e	0.1 N/A	0.4 414
SN-18	Ammonia Fugitive Emissions	Ammonia	0.21	0.37
SN-19	Diesel Fugitive Emissions	VOC	0.1	0.1
SN-22	Natural Gas-Fired Dewpoint Heater (Natural Gas-Fired, 5.01 MMBtu/hr)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X CO_2e Total HAPs	0.1 0.1 0.1 0.1 0.1 0.2 0.1 N/A 0.01	0.2 0.2 0.2 0.1 0.2 0.9 0.3 2570 0.05
SN-20	Standby Generator Engine Diesel Tank	VOC	0.3	0.1

EMISSION SUMMARY: IPS ONLY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-21	Emergency Firewater Pump Engine Diesel Tank	VOC	0.1	0.1

SECTION III: PERMIT HISTORY

1717-AOP-R0 was issued on April 16, 1999. It was the first operating air permit issued to Entergy- Arkansas, Inc. Lake Catherine. No physical changes in the method of operation at the facility occurred prompting this permit issuance.

The Lake Catherine facility had never been issued an air permit. These units were in existence prior to 1972, before the Air Code and SIP were promulgated, and have not undergone any modification. The units are considered to be "grandfathered." The emission limits listed in the emission summary table are less than the potential to emit. The Lake Catherine facility is taking emission limits pursuant to 8 CAR pt. 40 for fee purposes only. These limits are not being established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51, Subpart I or 40 CFR 51.166. These limits may be changed by the request of a permit modification if plant operating requirements change. Such a change may result in the facility paying higher permit fees. Appendix A outlines the potential to emit for the Lake Catherine facility. If this facility has a modification above the PSD significance level, Appendix A will be used as potential to emit pursuant to 40 CFR 52.21. The facility must meet the requirements of the Acid Rain Program and emissions from the facility must not violate the National Ambient Air Quality Standards (NAAQS).

1717-AOP-R1 was issued on May 8, 2001. After the issuance of the initial permit (1717-AOP-R0), it was discovered that the facility had potential problems with the permitted NO_x limits for short periods of time when the units were brought to maximum load. Also, it was found that Boiler #3 was exceeding the SO_2 limits. The exceedances were caused by low estimates of the heat input of the boilers. This modification allowed the facility to increase the estimated heat input for boilers and increased the permitted emission limits. No physical modifications were made to equipment at the facility.

Permit #1717-AO-R2 was issued on January 24, 2005. This was the first renewal of the Title V permit issued to this facility. There were no changes made in the physical operation of the facility, but the CO emissions were revised to reflect the use of AP-42 emission factors. Entergy believed these values to be more representative than the previous method used. Also, the particulate matter emission rates now account for both condensable and filterable fractions of particulate matter emissions. Also, hazardous air pollutants were listed in the permit for the first time.

Permit #1717-AOP-R3 was issued November 29, 2007. This modification will allowed Entergy-Lake Catherine Unit 4 to be considered a peaking unit and operated according to 40 CFR Part 75, Appendix E. No changes were made in the permitted emission rates.

Permit #1717-AOP-R4 was issued April 4, 2009. This permit modification was issued to incorporate the facility's Clean Air interstate Rule (CAIR) permit application. There were no permitted emission changes associated with this permitting action.

Permit #1717-AOP-R5 was issued August 15, 2011. This permit incorporated the facility's renewal permit application. This action decreased SO_2 emissions by 1049.1 tons per year. There were also changes of emissions of NO_x, PM and PM_{10}.

Permit #1717-AOP-R6 was issued September 26, 2014. This permit action retired three units 1 (SN-01), 2 (SN-01), and 3 (SN-02). Facility emissions decreased by 80.1 tons of PM/PM_{10}, 862.1 tons of SO_2, 58.1 tons of VOC, 885.3 tons of CO, 6,101.2 tons of NO_x, and HAPs decreased by 79.7 tons per year.

Permit #1717-AOP-R7 was issued October 26, 2016. This modification included the facility's renewal permit application. This modification included incorporation of the existing diesel-fired emergency generator engine as SN-10. Also, this modification removed permit provisions related to the vacated Clean Air Interstate Rule (CAIR) and incorporation of the applicable requirements of the Cross-State Air Pollution Rule (CSAPR). Insignificant Activities were updated as well. Facility emissions increased by 0.4, 0.5, 2.7, 1.3, 5.4, and 20.4 tons per year of PM_{10}, PM, SO_2, VOC, CO, and NO_x respectively.

Permit #1717-AOP-R8 was issued June 15, 2021. This modification included a specific condition outlining the facility's method of complying with Phase II Regional Haze State Implementation Plan requirements for SO_2 and PM. Also, Fuel Oil Storage Tanks, SN-04 through SN-09, were removed from the facility. This modification decreased permitted emissions by 0.6 tons per year of VOC.

Permit #1717-AOP-R9 was issued January 7, 2022. This modification included the facility's renewal permit application and a specific condition requiring Unit 4 (SN-03) to cease operation by December 31, 2027, as obligated by the Settlement Agreement between Entergy, Sierra Club, and National Parks Conservation Association approved by the U.S. District Court Eastern District Court of Arkansas. There were no requested changes in method of operation or emissions with this modification.

SECTION IV: SPECIFIC CONDITIONS

Unit LC#4: SN-03 with Support Equipment

SN-03
C4 Unit 4 Boiler (Natural Gas)

Source Description

Unit LC#4 (Lake Catherine) is a one-unit electric generating station which generates electric energy for sale. SN-03 of Unit 4 is a boiler capable of 5850 MMBtu/hr (nominal rating 560 MWg (megawatts gross). Electricity is produced by using natural gas as fuel in the boiler to produce steam. The steam is used to drive the turbines which turn the electric generators.

The emission limits for this unit are established pursuant to 8 CAR § 40-701. The limits are not established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51, Subpart I, or 40 CFR 51.166. Therefore, while operating Unit LC#4, the facility is not subject to PSD if the hours of operation are to be increased.

No control devices are associated with this unit.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with SO_2 emissions shall be demonstrated through compliance with Specific Condition 8. Compliance with SN-03 NO_x emission rates shall be demonstrated by compliance with Specific Condition 9. Compliance with PM_{10}, CO, and VOC emissions shall be demonstrated through compliance with Specific Condition 6. Compliance is based on a 24-hr block average. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
03	Unit 4 – Natural Gas	PM_{10}	44.5	194.8
		SO_2	3.6	15.4
		VOC	32.2	141.0
		CO	140.4	615.0
		NO_x	3,393.0	14,861.4

2. The permittee shall not exceed the emission rates set forth in the following table. Compliance with PM emissions shall be demonstrated through compliance with Specific Condition 6. The HAP emissions listed for these sources are based upon published emission factors at the time of permit issuance. Any change in these emission factors will not constitute a violation of the HAP emission rates listed below. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
03	Unit 4 – Natural Gas	PM Total HAPs	44.5 11.05	194.8 48.38

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9 for SN-03 when firing natural gas. Compliance with the opacity limit shall be demonstrated by burning natural gas in the boiler.

SN	Limit	Regulatory Citation
03	40%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E

4. The permittee shall install, operate, and maintain O_2 monitors on the boilers. The permittee shall show a positive O_2 reading when the boilers are in operation. [8 CAR § 41-603, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

5. The permittee shall update, twice per day, records which demonstrate compliance with Specific Condition 4. These records shall be kept on site, and shall be made available to Department personnel upon request. Each individual month's readings shall be submitted in accordance with General Provision 7. [8 CAR § 41-603, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

6. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated by burning 100% natural gas. The permittee is accepting these limits for fee purposes only. These limits are not being established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51, Subpart I or 40 CFR 51.166. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	tpy
03	Unit 4	PM PM_{10} SO_2 VOC CO NO_x	194.8 194.8 15.4 141.0 615.0 14,861.4

7. In order to meet the Phase II Regional Haze State Implementation Plan requirements for SO_2 and PM, SN-03 shall burn only pipeline quality natural gas. By burning only pipeline quality natural gas, compliance with BART (Best Achievable Retrofit Technology) requirements applicable to SN-03 is demonstrated. [Administrative Order LIS 18-073 and 40 C.F.R. § 52 Subpart E]

Acid Rain Requirements (SN-03)

8. The permittee shall determine SO_2 emissions using the optional SO_2 emissions data protocol procedures in 40 CFR Part 75, Appendix D, Section 2.2 and 2.3. The records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision 7. [40 C.F.R. § 52 Subpart E and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

9. The permittee shall determine NO_X emissions for unit 4 (SN-03) using the optional NO_X emissions data protocol procedure in 40 CFR Part 75, Appendix E, section 2.4. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision 7. [40 C.F.R. § 52 Subpart E and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

10. In the event that Unit 4 exceeds the level required to be a peaking unit as defined in 40 CFR 72.2, the permittee shall maintain records, using CEMS for NO_X for the applicable unit(s), which demonstrate compliance with the limit set forth in this permit. If CEMS is required, it will be installed in accordance with 40 CFR Part 75, Appendix E, §1.1 which requires a NO_x CEMS to be installed and certified no later than December 31st of the calendar year following the year in which the peaking status was lost. The records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision 7. [40 C.F.R. § 52 Subpart E and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

11. The permittee shall submit an excess emissions report for SO_2 and NO_x for the source every six (6) months. The report may be submitted to the Department with the report described in General Provision 7. The report shall include the magnitude of excess emissions computed from the 40 CFR Part 75 monitoring data in pounds per hour, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

12. The permittee shall determine CO_2 emissions based on the measured carbon content of the fuel and the fuel and the procedures in appendix G of 40 CFR Part 75 to estimate CO_2 emissions (in ton/day) discharged to the atmosphere. [8 CAR § 41-204 and 40 C.F.R. § 75.10(a)(3)]

13. SN-03 is considered a gas-fired unit and is exempt from Part 75 opacity monitoring as per 40 CFR Part 75.10 (a) (4). [8 CAR § 41-204 and 40 C.F.R. § 72.2]

14. In the event a gas-fired unit is re-categorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system. Each continuous opacity monitoring system shall meet the design, installation, equipment, and performance specifications in Performance Specifications 1 in appendix B to part 60. [8 CAR § 41-204 and 40 C.F.R. § 74.14]

15. The permittee shall ensure that all required continuous emission monitoring systems are in operation and monitoring all unit emissions at all times that the affected unit combusts any fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. A copy of the CEM monitoring requirements can be found in Appendix B of this permit. [8 CAR § 41-603, 40 C.F.R. § 75.10, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

16. The permittee shall submit the required quarterly monitoring reports to EPA headquarters. [8 CAR § 41-204 and 40 C.F.R. § 75.10(c)]

17. The permittee shall perform Relative Accuracy tests, if applicable. [8 CAR § 41-204 and 40 C.F.R. § 75]

18. The permittee shall determine and record the heat input to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in Appendix F of 40 CFR Part 75. [8 CAR § 41-204 and 40 C.F.R. § 75.10(c)]

19. The affected unit (SN-03) is subject to and shall comply with applicable provisions of the Acid Rain Program. [8 CAR § 41-204 and 40 C.F.R. §§ 72, 73, and 75]

20. The Notice of CEMS certification testing is required at least 21 days prior to the CEMS certification testing. Test results must be submitted within 45 days after completion of the certification test. [8 CAR § 41-603, 40 C.F.R. § 75 Subpart G, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

21. A monitoring plan is required to be submitted for NO_x, SO_2, and O_2 or CO_2 monitoring. [8 CAR § 41-603, 40 C.F.R. § 75 Subpart G, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

22. The initial NO_x, and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation except the testing must occur prior to the date this unit is declared commercial in accordance with DOE Form EIA-860. [8 CAR § 41-603, 40 C.F.R. § 75 Subpart A, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

23. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times when combusting fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. [8 CAR § 41-603, 40 C.F.R. § 75.10, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

24. The permittee shall permanently cease operation of SN-03 no later than December 31, 2027. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN-10
Emergency Diesel Generator

Source Description

SN-10 is Lake Catherine's 700 Hp compression ignition 4-stroke diesel-fired emergency engine. The model year of the engine is 1970. The engine model number is VT12-700-GS.

Specific Conditions

25. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Conditions 29. [8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
10	700 Hp Emergency Diesel Generator	PM_{10} SO_2 VOC CO NO_x	0.4 3.0 0.6 5.0 18.9	0.4 3.3 0.6 5.4 20.4

26. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Conditions 29. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
10	700 Hp Emergency Diesel Generator	PM Total HAP	0.5 0.03	0.5 0.03

27. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
10	40%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E

28. Annual observations of the opacity from SN-10 shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated annually, kept on site, and made available to Division of Environmental Quality personnel upon request.
    a. The date and time of the observation.
    b. If visible emissions which appeared to be above the permitted limit were detected.
    c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
    d. The name of the person conducting the opacity observations.

29. The permittee shall not operate the emergency generator SN-10 in excess of 2,160 total hours (emergency and non-emergency) per calendar year in order to demonstrate compliance with the annual emission rate limits. Emergency operation in excess of these hours may be allowable but shall be reported and will be evaluated in accordance with 8 CAR § 41-502 and other applicable rules. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

30. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition 29. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The calendar year totals and each individual month’s data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

NESHAP ZZZZ Requirements

31. The emergency generator engine (SN-10) is subject to 40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This unit is classified as an existing compression-ignition (CI) emergency engine at a major source. Provided SN-10 does not or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii). [8 CAR § 41-204 and 40 C.F.R. § 63.6590(b)(3)(iii)]

32. The emergency generator engine (SN-10) must be operated in accordance with the requirements in paragraphs (f)(1) through (4) of 40 CFR §63.6640 (outlined in (a) through (d) of this condition). For the engine to be considered an emergency stationary RICE under Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of 40 CFR §63.6640 is prohibited. If SN-10 is not operated according to the requirements of paragraphs (f)(1) through (4) of 40 CFR §63.6640, the engine will not be considered an emergency engine under subpart ZZZZ and must meet all requirements for non-emergency engines. [8 CAR § 41-204 and 40 C.F.R. § 63.6640]

   a. There is no time limit on the use of SN-10 in emergency situations.
   b. SN-10 may be operated for any combinations of the purposes specified in paragraphs (f)(2)(i) through (iii) of 40 CFR §63.6640 (b)(i) through (iii) of this condition for a maximum of 100 hours per year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) of 40 CFR §63.6640 counts as part of the 100 hours per year allowed by this paragraph (f)(2).
      i. SN-10 may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, the regional transmission operator, or the insurance company associated with the engine. The owner or operator may petition the administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.
   c. SN-10 may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) or 40 CFR §63.6640. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial agreement with another entity.

Unit IPS-CT (SN-11 with Support Equipment)

SN-11, 14, 15, 16, 17, 18, 19, and 22
Unit 5 Natural Gas-Fired Simple-Cycle Combustion Turbine

Source Description

The Ironwood Power Station is a one-unit electric generating station which generates electric energy for sale. The electric generating unit (EGU), Unit #5 (IPS-CT), is a simple-cycle combustion turbine capable of a short-term maximum heat input of 4,119 MMBtu/hr, and a long-term average heat input of 4,056 MMBtu/hr (456 MWe). Electricity is produced by using natural gas as fuel to turn the turbine. The unit is a simple-cycle turbine, meaning that it generates electricity but not steam. Pipeline quality natural gas is delivered to the site via pipeline, where it is metered and piped to the natural gas-fired turbine SN-11. To prevent damage to the turbine, the natural gas fuel to SN-11 is indirectly heated in a 5.01 MMBtu/hr natural gas-fired dewpoint heater (SN-22).

A conventional selective catalytic reduction (SCR) system, using a 29-percent solution of aqueous ammonia as the reagent, will be used to control NOx emissions from the proposed combustion turbine. The system will be composed of aqueous ammonia storage and handling equipment, ammonia injection grid, and catalyst bed. The ammonia injection grid and the SCR catalyst bed will be installed downstream of the turbine at a location where the flue gas temperature will allow for SCR NO_x reduction reactions. Ammonia will be stored in a 40,000-gallon pressurized tank with no routine air emissions. Therefore, no emission point ID is assigned to the ammonia storage tank. However, potential fugitive emissions of ammonia (SN-18) come from piping components, such as valves, flanges, connectors, pumps, open-ended lines, and relief valves.

The CTG will be equipped with an oxidation catalyst (OC) system to minimize carbon monoxide (CO) and Volatile Organic Compound (VOC) emissions. The OC system will be composed of catalyst bed modules. It will be installed at the location where exhaust temperatures will optimize CO and VOC reduction reactions. The exhaust stream is then released to the atmosphere through the unit's stack (EPN IPS-CT / SN-11).

Planned startup and shutdown (SUSD) of the proposed simple cycle turbine will be part of the routine operations at the facility. A planned startup is defined as the period beginning when the combustion turbine receives a "turbine start" signal and an initial flame detection signal is recorded in the plant's control system and ending when the combustion turbine output achieves steady operation in the low NOx operating mode and the SCR and OC have achieved steady state operation, thereby achieving emissions compliance. A planned shutdown period will begin when the combustion turbine receives a shutdown command and the combustion turbine operating level drops below its minimum sustainable load. A combustion turbine's planned shutdown will end when a flame signal is no longer recorded in the plant's control system. Depending on future electricity demand, the new Lake Catherine Unit IPS will be classified either as an Intermediate Load Combustion Turbine or a Low Load Combustion Turbine under the New Source Performance Standard (NSPS) for Greenhouse Gas (GHG) Emissions from Stationary Combustion Turbine EGUs, found at 40 CFR 60 Subpart TTTTa (NSPS TTTTa).

Entergy also proposes to construct two small horizontal fixed-roof tanks to store any natural gas condensate that may be present in the incoming natural gas fuel. Both tanks (EPNs: IPS-TK3 / SN-14 and IPS-TK4 / SN-15) have a volume of 400 gal and are equipped with an atmospheric vent.

The turbine has a dedicated lubrication system, including SN-16 (Combustion Turbine Lube Oil Vent). Lubrication oil is circulated through the turbine's machinery from the system's oil sump. The sump is equipped with a vent controlled by a built-in oil mist eliminator. Emissions are VOC and PM. These are based on replacement rates of lube oil for similar units.

The site has piping in natural gas, diesel, and ammonia service. Potential fugitive emissions of natural gas (SN-17) and diesel (SN-19) come from piping components, such as valves, flanges, connectors, pumps, open-ended lines, and relief valves, in service for that substance. Emissions are calculated using records of the number of each type of component for each substance.

Specific Conditions

33. The permittee shall not exceed the emission rates set forth in the following table.
    a. Compliance with SN-11's emission rates shall be demonstrated by heat input recordkeeping and as follows:
        i. PM/PM_{10},$/PM_{2.5}$: by use of pipeline-quality natural gas.
        ii. VOC, CO: by use of an add-on catalytic oxidation control system
    b. Compliance with SN-14, 15, 16, 17, and 19's emission rates shall be demonstrated by proper operation and maintenance of these sources and SN-11.
    c. Compliance with SN-22's emission rates shall be demonstrated by use of pipeline-quality natural gas.

    [8 CAR § 41-801 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
11*	IPS-CT	Simple-Cycle Combustion Turbine Unit 5 (Natural Gas-Fired, 467 MWe, 4,119 MMBtu/hr max)	PM PM_{10} $PM_{2.5}$ VOC CO CO_2e H_2SO_4	36.1 36.1 36.1 427.7 863.6 N/A 17.71	30.1 30.1 30.1 86.2 222.0 683,187 12.35
14	IPS-TK3	Natural Gas Condensate Tank #3	VOC	3.5	0.1
15	IPS-TK4	Natural Gas Condensate Tank #4	VOC	3.5	0.1
16	IPS-LOVCT	Combustion Turbine Lube Oil Vent	PM PM_{10} $PM_{2.5}$ VOC	0.1 0.1 0.1 0.1	0.1 0.1 0.1 0.1
17	IPS-NGFUG	Natural Gas Fugitive Emissions	VOC CO_2e	0.1 N/A	0.4 414
19	IPS-DSLFUG	Diesel Fugitive Emissions	VOC	0.1	0.1
22	IPS-NGDPHTR	Natural Gas-Fired Dewpoint Heater (Natural Gas-Fired, 5.01 MMBtu/hr)	PM PM_{10} $PM_{2.5}$ VOC CO CO_2e	0.1 0.1 0.1 0.1 0.2 N/A	0.2 0.2 0.2 0.2 0.9 2,570

* Annual emission limits include those from Startup and Shutdown events in Specific Condition #36.

34. The permittee shall not exceed the emission rates set forth in the following table.
    a. Compliance with SN-11's emission rates shall be demonstrated by heat input recordkeeping and as follows:
        i. SO_2: by use of pipeline-quality natural gas, including sulfur content recordkeeping.
        ii. NO_x: by use of an add-on SCR control system and CEMS.
    b. Compliance with SN-22's emission rates shall be demonstrated by use of pipeline-quality natural gas.

[8 CAR § 41-401 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
11	IPS-CT	Simple-Cycle Combustion Turbine Unit 5 (Natural Gas-Fired, 467 MWe, 4,119 MMBtu/hr max)	SO_2 NO_x	11.6 248.1	8.1 344.1
22	IPS-NGDPHTR	Natural Gas-Fired Dewpoint Heater (Natural Gas-Fired, 5.01 MMBtu/hr)	SO_2 NO_x	0.1 0.1	0.1 0.3

35. The permittee shall not exceed the emission rates set forth in the following table.
    a. Compliance with SN-11's emission rates shall be demonstrated by heat input recordkeeping and as follows:
        i. HAPs by use of pipeline-quality natural gas.
        ii. H_2SO_4: by use of pipeline-quality natural gas, including sulfur content recordkeeping.
    b. Compliance with SN-22's emission rates shall be demonstrated by use of pipeline-quality natural gas.

[8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
11	IPS-CT	Simple-Cycle Combustion Turbine Unit 5 (Natural Gas-Fired, 467 MWe, 4,119 MMBtu/hr max)	Total HAPs Ammonia	2.46 60.33	3.43 84.19
18	IPS-AMMFUG	Ammonia Fugitive Emissions	Ammonia	0.21	0.37
22	IPS-NGDPHTR	Natural Gas-Fired Dewpoint Heater (Natural Gas-Fired, 5.01 MMBtu/hr)	Total HAPs	0.01	0.05

36. The permittee is limited to the following emissions during Startup and Shutdown events. These total durations of these events are limited by Specific Condition #37 [8 CAR § 41-401, 8 CAR § 41-801 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Entergy Emission Source ID	Description	Pollutant	lb/event, maximum	Effective lb/hr**	tpy*
11	IPS-CT	Simple-Cycle Combustion Turbine Unit 5 (Natural Gas-Fired, 467 MWe, 4,119 MMBtu/hr max)	PM PM_{10} $PM_{2.5}$ SO_2 VOC CO NO_X SAM Ammonia	36.1 36.1 36.1 11.6 425.0 845.0 134.0 17.71 60.33	36.1 36.1 36.1 11.6 427.7 863.6 248.1 17.71 60.33	2.2 2.2 2.2 0.6 78.8 170.6 27.6 0.89 6.09

* Emissions listed here are included in the annual emission limits in Specific Conditions #33, 34, and 35.
** For VOC, CO, and NO_X, effective lb/hr is based on 32 minutes per SSM event, plus the maximum lb/hr emissions for normal operations for the rest of the hour. For other pollutants, effective lb/hr is the same as for normal operations. For particulates, SO_2, SAM, and Ammonia, hourly emissions are no greater than normal operation.

37. The permittee is limited to a duration of 160 hours of Startup and 45 hours of Shutdown events per 12-month rolling period. [8 CAR § 41- 801, 8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

38. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #37.
    a. Records shall include the time and dates for each startup event and shutdown event for each month, hours spent in Startup, and hours spent in Shutdown for each month, and 12-month rolling totals for Startup hours and for Shutdown hours.
    b. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain.
    c. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request, and submitted in accordance with General Provision #7.

    [8 CAR § 41- 801, 8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

39. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with the opacity limit shall be demonstrated by burning natural gas in the turbine and dew point heater. Compliance with the opacity limit for the lube oil vent is use of a mist eliminator.

SN	Entergy Emission Source ID	Limit	Regulatory Citation
11	IPS-CT	5%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E
16	IPS-LOVCT	5%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E
22	IPS-NGDPHTR	5%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E

40. An initial observation of the opacity from SN-11 shall be conducted by a certified EPA Reference Method 9 reader. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be kept on site and made available to Division of Environmental Quality personnel upon request.
    a. The date and time of the observation.
    b. If visible emissions which appeared to be above the permitted limit were detected.
    c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
    d. The name of the person conducting the opacity observations.

    [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

41. The permittee may not operate the IPS Unit and its associated support sources (SN-11 through SN-22) until all of the LC Unit #4 (SN-01 through SN-10 and the equipment labeled as part of LC Unit #4 in the Insignificant Activities List) has been removed from service. Once any part of the IPS Unit is brought into service, any part of LC Unit #4 may not be brought back into service on site without further permitting approval. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

42. SN-11 and SN-22 shall use only pipeline quality natural gas as fuel. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

43. The natural gas sulfur content may not exceed 1.0 gr/scf of Total Sulfur at any time and 0.5 gr/scf Total sulfur on any 12-month monthly rolling total. The sulfur content limit is to demonstrate the SO_2 and BACT H_2SO_4 emission rates. The permittee must maintain on-site records, such as a current, valid purchase contract, tariff sheet, or transportation contract, documenting that total sulfur content for the natural gas. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41- 801, 8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

44. The permittee shall not exceed the limits set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. [8 CAR § 41- 801, 8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

Pollutant Subject to PSD	BACT Limit	Control Technology	Compliance Method	Testing Condition(s)	Testing Method(s)
PM_{10} $PM_{2.5}$ PM	0.0052 lb/ MMBtu	Good Combustion Techniques, Use of Pipeline Quality Natural Gas	initial testing	45	EPA Test Methods 201A and 202
VOC	1.0 ppmvd @ 15% O2	Good Combustion Techniques, Add-on Catalytic Oxidation Control System	initial testing, then every 5 years	0	EPA Test Method 25 or 25A
CO	4.0 ppmvd @ 15% O_2	Good Combustion Techniques, Add-on Catalytic Oxidation Control System	initial testing, then every 5 years	47	EPA Test Method 10
H_2SO_4	17.70 lb/hr 1.0 grains S/100 scf, 0.5 grains S/100 scf annual-average	Use of Low-Sulfur Pipeline Quality Natural Gas	initial testing, then fuel content documentation	0	EPA Test Method 8

Pollutant Subject to PSD	BACT Limit	Control Technology	Compliance Method	Testing Condition(s)	Testing Method(s)
CO_2e	Intermediate-load mode (per TTTTa): 1,170 lb CO_2e/MWh gross energy output max on 12 operating-month average Low-load mode (per TTTTa): 120 lb CO_2e/MWh heat input max	Operating a System with Relatively High Thermal Efficiency, Use of Pipeline Quality Natural Gas as Relatively Low-Carbon Fuel	Calculation	None	calculation per Part 98 for CO_2e total

45. The permittee shall initially test SN-11 for PM, PM_{10}, and $PM_{2.5}$ using EPA Test Methods 201A and 202.
    a. Testing shall be conducted during normal, steady-state operations.
    b. Testing shall use a 3-hour average.
    c. This test shall take place in accordance with Plantwide Condition #3.
    d. Testing shall be conducted with the source operating at least at 90% of its permitted capacity of 4,119 MMBtu/hr. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
    e. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

46. The permittee shall initially, and thereafter, every five years, test SN-11 for VOC using EPA Test Method 25 or 25A.
    a. Testing shall be conducted during conducted during normal, steady-state operations.
    b. Testing shall use a 3-hour average.
    c. This test shall take place in accordance with Plantwide Condition #3.
    d. Testing shall be conducted with the source operating at least at 90% of its permitted capacity of 4,119 MMBtu/hr. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
    e. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.
    f. Testing shall also be conducted with the source operating at 65-75% of its permitted capacity of 4,119 MMBtu/hr to demonstrate compliance with annual emission limits.
    g. For both loading conditions, the permittee must demonstrate that the VOC concentration does not exceed 1.0 ppm at 15% O_2 for any 3-hour average at either of the two testing conditional loads.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

47. The permittee shall initially, and thereafter, every five years, test SN-11 for CO using EPA Test Method 10.
    a. Testing shall be conducted during normal, steady-state operations.
    b. Testing shall use a 3-hour average.
    c. This test shall take place in accordance with Plantwide Condition #3.
    d. Testing shall be conducted with the source operating at least at 90% of its permitted capacity of 4,119 MMBtu/hr. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
    e. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

48. The permittee shall test SN-11 for Sulfuric Acid Mist (H_2SO_4) using EPA Test Method 8.
    a. When using Test Method 8 to test for SO_2, the same testing shall be used to demonstrate compliance with both SO_2 and Sulfuric Acid Mist (H_2SO_4). See Condition #50.
    b. Testing shall be conducted during normal, steady-state operations. To avoid interference from ammonia, testing may take place before SCR.
    c. Testing shall use a 3-hour average.
    d. This test shall take place in accordance with Plantwide Condition #3.
    e. Testing shall be conducted with the source operating at least at 90% of its permitted capacity of 4,119 MMBtu/hr. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
    f. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

49. The permittee shall not exceed the limits for SN-11 set forth in the following table and must install the control devices or implement the pollution prevention measures set forth in the following table. [8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

SN-11	Emission Limit	Control Technology	Compliance Method	Testing Condition(s)	Testing Method(s)
SO_2	0.060 lb/ MMBtu heat input or 0.90 lb/MWh energy output	Use of Low-Sulfur Pipeline Quality Natural Gas	initial testing, sulfur content of fuel	0	EPA Test Method 8 with H_2SO_4
NOx	15.0 ppmvd@ 15% O_2	Good Combustion Techniques, Add-on Catalytic Oxidation Control System	CEMS	N/A	N/A

50. The permittee shall test SN-11 for SO_2 using EPA Test Method 8.
    a. When using Test Method 8 to test initially for SO_2, concurrent testing shall be used to demonstrate compliance with SO_2 and Sulfuric Acid Mist (H_2SO_4).
    b. Testing shall be conducted during normal, steady-state operations.
    c. Testing shall use a 3-hour average.
    d. This test shall take place in accordance with Plantwide Condition #3.
    e. Testing shall be conducted with the source operating at least at 90% of its permitted capacity of 4,119 MMBtu/hr. Emission testing results shall be extrapolated to correlate with 100% of the permitted capacity to demonstrate compliance. Failure to test within this range shall limit the permittee to operating within 10% above the tested rate.
    f. The permittee shall measure the operation rate during the test and if testing is conducted below 90% of the permitted capacity, records shall be maintained at all times to demonstrate that the source does not exceed operation at 10% above the tested rate.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

51. The permittee shall install and maintain a NOx CEMS at the outlet of the SCR catalyst at SN-11 to monitor the output concentration and maintain compliance with the limit of 15 ppm @ 15% O_2. The CEMS shall be operated in accordance with the Department Continuous Emission Monitoring Systems Conditions except where a specific requirement is given by this permit. A copy of the Department Continuous Emission Monitoring Systems Conditions is provided in Appendix B. [8 CAR § 41-603, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

52. The permittee shall install, operate, and maintain a continuous parameter monitoring system (CPMS) that measures and records the catalyst temperature to ensure a range from 500ºF to 700ºF. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

53. The permittee shall maintain hourly records of the NO_X ppm, the lbs/hr NO_X emitted, and the ammonia injection rate established for control of NO_x and verified by the CEMS. These limits are intended to show compliance with the emission limits in Specific Conditions #34, #35, and #49. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-603, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

54. The permittee shall not exceed a Higher Heating Value (HHV)based firing rate (or heat input) of 10,659,168 MMBtu/yr of fuel at SN-11 per rolling 12 month period.
    a. Any exceedance of this operating limit constitutes a reportable permit deviation.
    b. This is based on a maximum long-term average firing rate of 4,056 MMBtu/hour for SN-11, a maximum capacity factor of 30%, and usage of only pipeline-quality natural gas.
    c. If the unit as constructed is capable of exceeding the maximum hourly firing rate, further permitting action is necessary.

    [8 CAR § 41- 801, 8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

55. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #54.
    a. Heat input monitoring shall include the firing rate (or heat input) for each month, and a 12-month rolling total, and shall be based on firing rate monitoring required by the federal acid rain program pursuant to 40 C.F.R. § 75.10(c).
    b. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain.
    c. The twelve month rolling totals and each individual month's data shall be maintained on-site, made available to Division of Environmental Quality personnel upon request, and submitted in accordance with General Provision #7.

    [8 CAR § 41- 801, 8 CAR § 41-401 et seq. and 40 C.F.R. § 52 Subpart E]

Acid Rain Requirements

56. The permittee shall determine SO_2 emissions using the optional SO_2 emissions data protocol procedures in 40 CFR Part 75, Appendix D, Section 2.2 and 2.3. The records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision 7. [40 C.F.R. § 52 Subpart E and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

57. The permittee shall determine NO_X emissions for unit 5 (SN-11) using the optional NO_X emissions data protocol procedure in 40 CFR Part 75, Appendix E, section 2.4. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision 7. [40 C.F.R. § 52 Subpart E and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

58. In the event that Unit 5 exceeds the level required to be a peaking unit as defined in 40 CFR 72.2, the permittee shall maintain records, using CEMS for NO_X for the applicable unit(s), which demonstrate compliance with the limit set forth in this permit. If CEMS is required, it will be installed in accordance with 40 CFR Part 75, Appendix E, §1.1 which requires a NO_x CEMS to be installed and certified no later than December 31st of the calendar year following the year in which the peaking status was lost. The records may be used by the Department for enforcement purposes. The records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision 7. [40 C.F.R. § 52 Subpart E and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

59. The permittee shall submit an excess emissions report for SO_2 and NO_x for the source every six (6) months. The report may be submitted to the Department with the report described in General Provision 7. The report shall include the magnitude of excess emissions computed from the 40 CFR Part 75 monitoring data in pounds per hour, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

60. The permittee shall determine CO_2 emissions based on the measured carbon content of the fuel and the procedures in appendix G of 40 CFR Part 75 to estimate CO_2 emissions (in ton/day) discharged to the atmosphere. [8 CAR § 41-204 and 40 C.F.R. § 75.10(a)(3)]

61. SN-11 is considered a gas-fired unit and is exempt from Part 75 opacity monitoring as per 40 CFR Part 75.10 (a) (4). [8 CAR § 41-204 and 40 C.F.R. § 72.2]

62. In the event a gas-fired unit is re-categorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system. Each continuous opacity monitoring system shall meet the design, installation, equipment, and performance specifications in Performance Specifications 1 in appendix B to part 60. [8 CAR § 41-204 and 40 C.F.R. § 74.14]

63. The permittee shall ensure that all required continuous emission monitoring systems are in operation and monitoring all unit emissions at all times that the affected unit combusts any fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. A copy of the CEM monitoring requirements can be found in Appendix B of this permit. [8 CAR § 41-603, 40 C.F.R. § 75.10, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

64. The permittee shall submit the required quarterly monitoring reports to EPA headquarters. [8 CAR § 41-204 and 40 C.F.R. § 75.10(c)]

65. The permittee shall perform Relative Accuracy tests, if applicable. [8 CAR § 41-204 and 40 C.F.R. § 75]

66. The permittee shall determine and record the heat input to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in Appendix F of 40 CFR Part 75. [8 CAR § 41-204 and 40 C.F.R. § 75.10(c)]

67. The affected unit (SN-11) is subject to and shall comply with applicable provisions of the Acid Rain Program. [8 CAR § 41-204 and 40 C.F.R. §§ 72, 73, and 75]

68. The Notice of CEMS certification testing is required at least 21 days prior to the CEMS certification testing. Test results must be submitted within 45 days after completion of the certification test. [8 CAR § 41-603, 40 C.F.R. § 75 Subpart G, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

69. A monitoring plan is required to be submitted for NO_x, SO_2, and O_2 or CO_2 monitoring. [8 CAR § 41-603, 40 C.F.R. § 75 Subpart G, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

70. The initial NO_x, and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation except the testing must occur prior to the date this unit is declared commercial in accordance with DOE Form EIA-860. [8 CAR § 41-603, 40 C.F.R. § 75 Subpart A, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

71. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times when combusting fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. [8 CAR § 41-603, 40 C.F.R. § 75.10, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

NSPS KKKKa Requirements (SN-11)

72. SN-11 is a new simple-cycle gas turbine firing with a heat input at peak load greater than 850 MMBtu/hr, fired exclusively with natural gas, and commencing construction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). [8 CAR § 41-204 and 40 C.F.R. §60.4305a(a)]

73. Except as provided for in paragraph (c) of this section, for each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO_X that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of this section. If you choose to use NO_X CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis. [8 CAR § 41-204 and 40 CFR 60.4320a(a)]

74. For the purpose of determining compliance with the applicable emissions standard, you must also meet the requirements specified in paragraphs (b)(1) through (4) of this section, as applicable to your affected facility. [8 CAR § 41-204 and 40 CFR 60.4320a(b)]

a. The NO_X emission standard that is applicable to your affected facility shall be determined on an operating-hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of this section. Determining the hourly NO_X emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390a. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour.

b. As an alternative to the requirements specified in paragraph (b)(1) of this section, you may elect to use the lowest NO_X emission standard that is applicable to your affected facility, as determined using table 1 to this subpart, for the entire required compliance period.

c. During each operating hour when only natural gas is combusted, you must meet the NO_X emission standard as determined by the applicable size category in table 1 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing natural gas for that operating hour.

Combustion Turbine Type	Combustion Turbine Base Load Rated Heat Input (HHV)	Input-based NOx emission standard	Output-based NOx emission standard
New, firing natural gas with utilization rate ≤45 percent and with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.83 lb NOx/MWh gross output
Operating at ambient temperatures less than 0 °F (−18 °C and/or operating at less than 70 percent of the base load rating	>300 MMBtu/h	96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/MMBtu)	N/A

75. You must meet the applicable NO_X emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction). [8 CAR § 41-204 and 40 CFR 60.4320a(d)]

76. Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. [8 CAR § 41-204 and 40 CFR 60.4330a(a)(1)]

77. You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction. [8 CAR § 41-204 and 40 CFR 60.4333a(a)]

78. If you own or operate a stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. Thereafter, unless you perform continuous monitoring consistent with § 60.4335a, § 60.4340a, or § 60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (6) of this section. The facility has chosen to operate and install a NOx CEMs and conduct monitoring consistent with the above. Therefore, subsequent performance testing is not required. [8 CAR § 41-204 and 40 CFR 60.4333a(b)]

79. Except as provided for in paragraph (c)(1) or (2) of this section, for each stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_X emissions according to the provisions in § 60.4345a. If your stationary combustion turbine is equipped with a NO_X CEMS, those measurements must be used to determine excess emissions. If your stationary combustion turbine does not use water injection, steam injection, or post-combustion controls to meet the applicable NO_X emissions standard in § 60.4320a, you may elect to demonstrate continuous compliance with an input-based standard according to the provisions in § 60.4340a. [8 CAR § 41-204 and 40 CFR 60.4333a(c)(2)]

80. An owner or operator of a stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330a must demonstrate compliance using one of the methods specified in this section. The facility has chosen option 3. [8 CAR § 41-204 and 40 CFR 60.4333a(d)(3)]

Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370a.

81. Each CEMS measuring NO_X emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of this section. [8 CAR § 41-204 and 40 CFR 60.4345a(a)]
    a. You must install, certify, maintain, and operate a NO_X monitor to determine the hourly average NO_X emissions in the units of the standard with which you are complying.
    b. If you elect to comply with an input-based or mass-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.
    c. If you elect to comply with the part-load NO_X emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

82. Each NO_X CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_X emissions rate. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 with approval from the Administrator or delegated authority, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. [8 CAR § 41-204 and 40 CFR 60.4345a(b)]

83. During each full operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two data points (one in each of two quadrants) are required for each monitor. [8 CAR § 41-204 and 40 CFR 60.4345a(c)]

84. Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart. [8 CAR § 41-204 and 40 CFR 60.4345a(d)]

85. Each watt meter, steam flow meter, and each pressure or temperature measurement device must be installed, calibrated, maintained, and operated according to manufacturer's instructions. [8 CAR § 41-204 and 40 CFR 60.4345a€]

86. You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of § 60.13(d), (e), and (h). For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of this paragraph (f) by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in § 60.13(d)(1). [8 CAR § 41-204 and 40 CFR 60.4345a(f)]

87. At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis. [8 CAR § 41-204 and 40 CFR 60.4345a(g)]

88. If you demonstrate continuous compliance using a CEMS for measuring NO_X emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating-hours, 30-operating-days, or 12-calendar-month), during which the average NO_X emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO_X emissions standard specified in § 60.4320a as determined using the procedures specified in this section that apply to your stationary combustion turbine. [8 CAR § 41-204 and 40 CFR 60.4350a(a)]

89. The NO_X CEMS data for each operating hour as measured according to the requirements in § 60.4345a must be used to determine the hourly average NO_X emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO_X, diluent, flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO_X emissions. All data points that are not collected during out-of-control periods must be used to determine the hourly average NO_X emissions. [8 CAR § 41-204 and 40 CFR 60.4350a(b)]

90. For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO_X emissions in units of lb/MMBtu or lbs, as applicable, using the appropriate equation from EPA Method 19 in appendix A-7 to this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [8 CAR § 41-204 and 40 CFR 60.4350a(c)]

91. Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75. For units complying with the 12-calendar-month mass-based standard, emissions for hours of missing data shall be estimated by using the average emissions rate of non-out-of-control hours within ±10 percent of the hour of missing data within the 12-calendar-month period. If non-out-of-control data is not available, the maximum hourly emissions rate during the 12-calendar-month period shall be used. [8 CAR § 41-204 and 40 CFR 60.4350a(d)]

92. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value. [8 CAR § 41-204 and 40 CFR 60.4350a(e)]

93. For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NO_X emissions are determined on a 4-operating-hour averaging period basis using the NO_X CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NO_X emissions standard in table 1 to this subpart. [8 CAR § 41-204 and 40 CFR 60.4350a(g)(1 and 2)]

   a. For each 4-operating-hour period, compute the 4-operating-hour rolling average NO_X emissions as the heat input weighted average of the hourly average of NO_X emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NO_X emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average NO_X emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).
   b. If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NO_X emissions rate and the applicable 4-operating-hour rolling average NO_X emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this paragraph (g)(2).

Equation 4 to Paragraph (g)(2)

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 4)}$$

Where:
E = 4-operating-hour rolling average NO_X emissions (lb/MMBtu or ng/J);
E_i = Hourly average NO_X emissions rate or emissions standard for operating hour "i" (lb/MMBtu or ng/J); and
Q_i = Total heat input to stationary combustion turbine for operating hour "i" (MMBtu or J as appropriate).

94. If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333a(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of this section, as applicable to your stationary combustion turbine. [8 CAR § 41-204 and 40 CFR 60.4372a(a)]

95. If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330a(a), then the fuel combusted must have a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less. [8 CAR § 41-204 and 40 CFR 60.4372a(b)]

96. Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of this chapter documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas. Your stationary combustion turbine may not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. [8 CAR § 41-204 and 40 CFR 60.4372a(e)]

97. An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction. [8 CAR § 41-204 and 40 CFR 60.4375a(a)]

98. The notification requirements of § 60.8 apply to the initial and subsequent performance tests. [8 CAR § 41-204 and 40 CFR 60.4375a(b)]

99. Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.[8 CAR § 41-204 and 40 CFR 60.4375a(e)]

100. You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. [8 CAR § 41-204 and 40 CFR 60.4375a(f)]

101. If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g). [8 CAR § 41-204 and 40 CFR 60.4375a(g)]

   a. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov*, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqps_cbi@epa.gov* to request a file transfer link.
   b. If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

102. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section. [8 CAR § 41-204 and 40 CFR 60.4375a(h)]
    a. You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.
    b. The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.
    c. The outage may be planned or unplanned.
    d. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
    e. You must provide to the Administrator a written description identifying:
        i. The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;
        ii. A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
        iii. A description of measures taken or to be taken to minimize the delay in reporting; and
        iv. The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.
    f. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
    g. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

103. If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section. [8 CAR § 41-204 and 40 CFR 60.4375a(i)]
    a. You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage)

b. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
c. You must provide to the Administrator:
    i. A written description of the *force majeure* event;
    ii. A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;
    iii. A description of measures taken or to be taken to minimize the delay in reporting; and
    iv. The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.
d. The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
e. In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

104. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation. [8 CAR § 41-204 and 40 CFR 60.4375a(j)]

105. For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) and (2) of this section. [8 CAR § 41-204 and 40 CFR 60.4380a(b)]

a. An excess emission that must be reported is any unit operating period in which the 4-operating-hour average NO_X emissions rate, 30-operating-day rolling average NO_X emissions rate, 4-hour mass-based emissions rate, or the 12-calendar-month mass-based emissions rate exceeds the applicable emissions standard in § 60.4320a as determined in § 60.4350a.
b. A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: NO_X concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

106. For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO_X emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section. [8 CAR § 41-204 and 40 CFR 60.4380a(c)]
    a. Excess emissions that must be reported are each 4-operating-hour rolling average in which any monitored parameter (as averaged over the 4-operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.
    b. Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data that are used to calculate the emission rate, as applicable, used to determine compliance, are either not recorded or are out-of-control.

107. If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitor downtime are defined as follows: [8 CAR § 41-204 and 40 CFR 60.4385a(a)]
    a. For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard.
    b. If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (*i.e.,* daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.
    c. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

108. If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard. [8 CAR § 41-204 and 40 CFR 60.4385a(b)]

109. For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (c)(1) and (2) of this section. [8 CAR § 41-204 and 40 CFR 60.4385a(c)]
   a. An excess emission that must be reported is any unit operating period in which the 4-operating-hour or 30-operating-day rolling average SO_2 emissions rate exceeds the applicable emissions standard in § 60.4330a as determined in § 60.4374a.
   b. A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: SO_2 concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

110. You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7. [8 CAR § 41-204 and 40 CFR 60.4390a(a)]

111. An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO_X standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable. [8 CAR § 41-204 and 40 CFR 60.4390a(b)]

112. An owner or operator of a stationary combustion turbine that uses the tuning NO_X standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance. [8 CAR § 41-204 and 40 CFR 60.4390a(c)]

113. An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters. [8 CAR § 41-204 and 40 CFR 60.4390a(e)]

114. An owner or operator of a stationary combustion turbine complying with the fuel-based SO_2 standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract. [8 CAR § 41-204 and 40 CFR 60.4390a(f)]

115. Consistent with § 60.7(c), all reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period. [8 CAR § 41-204 and 40 CFR 60.4395a]

116. If you use a CEMS, the performance test must be performed according to the procedures specified in paragraph (b) of this section. [8 CAR § 41-204 and 40 CFR 60.4405a(a)]

117. The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section. [8 CAR § 41-204 and 40 CFR 60.4405a(b)]
   a. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±25 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.
   b. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.
   c. Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under § 60.4320a and to provide the required reference method data for the RATA of the CEMS described under § 60.4342a.
   d. Compliance with the applicable emissions standard in § 60.4320a is achieved if the sum of the NO_X emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu, ppm, lb/MWh, or kgs, does not exceed the emissions standard.

118. If you are an owner or operator of an affected facility complying with the fuel-based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8. [8 CAR § 41-204 and 40 CFR 60.4415a(a)]

119. If you are an owner or operator of an affected facility complying with the SO_2 emissions standard must conduct the performance test by measuring the SO_2 emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section. [8 CAR § 41-204 and 40 CFR 60.4415a(b)]

a. Measure the SO_2 concentration using EPA Method 6, 6C, or 8 in appendix A-4 to this part or EPA Method 20 in appendix A-7 to this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then use equation 1 to this paragraph (b)(1) to calculate the SO_2 emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:
E = SO_2 emissions rate, in lb/MWh;
1.664×10^{-7} = Conversion constant, in lb/dscf-ppm;
$(SO_2)_c$ = Average SO_2 concentration for the run, in ppm;
Q_{std} = Average stack gas volumetric flow rate, in dscf/h; and
P = Average gross electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350a(f)(2).

b. Measure the SO_2 and diluent gas concentrations, using either EPA Method 6, 6C, or 8 in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the SO_2 emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2, 3, and 4 in § 60.4374a to calculate the SO_2 emissions rate in lb/MWh.

NSPS TTTTa Requirements (SN-11)

120. The gas turbine must meet CO_2 emission performance levels specified in Table 1 of NSPS Subpart TTTTa. The proposed gas turbine will be classified as either an intermediate load or a low load combustion turbine depending on the quantity of electricity sold to the grid. The required NSPS TTTTa CO_2 performance level is dependent on this load status classification, which may change over time depending on local electricity demand. For the case of an intermediate load combustion turbine (capacity factor > 20% and ≤ 40%) with a firing capacity greater than 2,000 MMBtu/hr, the applicable CO_2 limit in NSPS TTTTa Table 1 is 1,170 lb CO_2/MW-hr of gross energy output. For the case of a low load combustion turbine (capacity factor ≤ 20%) with a firing capacity greater than 2,000 MMBtu/hr, the applicable CO2 limit in NSPS TTTTa Table 1 is 120 lb CO_2/MMBtu-HHV of heat input. The gas turbine will never have a capacity factor > 30%, which is a federally enforceable operating limit and the basis for the PSD project emissions accounting for this facility. [8 CAR § 41-204 and 40 CFR 60.5520a(a)]

121. The gas turbine must comply with the applicable gross energy output standard for intermediate load operations, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard when applicable. [8 CAR § 41-204 and 40 CFR 60.5520a(b)]

122. A gas turbine such as SN-11 that is only permitted to burn one or more uniform fuels, such as natural gas, is only subject to the monitoring requirements in paragraph (d)(1). You must also maintain record of electric sales to determine whether the combustion turbine is subject to the intermediate load or low load standards in NSPS TTTTa Table 1 as per § 60.5560a(h). [8 CAR § 41-204 and 40 CFR 60.5520a(d)]

123. Gas turbines such as Source SN-11 that are only permitted to burn fuels with a consistent chemical composition, such as natural gas, are not subject to any other heat input monitoring or reporting requirements under this subpart. Stationary combustion turbines qualifying under this paragraph, including Source SN-11, are only required to maintain purchase records for permitted fuels to comply with heat input monitoring requirements. [8 CAR § 41-204 and 40 CFR 60.5520a(d)(1)]

124. If the gas turbine that is subject to a gross energy output CO_2 limit in units of lb CO_2/MW-hr gross energy output, including intermediate load operations, you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output from the gas turbine. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). [8 CAR § 41-204 and 40 CFR 60.5535a(d)(1)

125. The permittee shall demonstrate compliance with the applicable CO_2 emission standard (intermediate load or low load) in table 1 to this subpart for the gas turbine as specified in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for the gas turbine in units of the applicable emissions standard (i.e., lb CO_2/MW-hr gross energy output or lb CO_2/MMBtu- HHV energy input). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) and the generating load data from § 60.5535a(d)(1) for output-based calculations. For energy input-based calculations, use the heat input data from § 60.5535a(d)(2). [8 CAR § 41-204 and 40 CFR 60.5540a(a)]

126. The permittee shall submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected gas turbine EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter. The quarterly reports must contain the applicable information specified in 40 CFR 60.5555a(a)(2) and (3). [8 CAR § 41-204 and 40 CFR 60.5555a(a)(1)]

127. The permittee must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA. [8 CAR § 41-204 and 40 CFR 60.5555a(b)]

128. For the affected gas turbine EGU that is subject to NSPS Subpart TTTTa and is also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter. [8 CAR § 41-204 and 40 CFR 60.5555a(c)(1)]

129. The permittee must maintain records of the information you used to demonstrate compliance with NSPS Subpart TTTTa as specified in § 60.7(b) (startup, shutdown and malfunction records) and 60.7(f) (CEMS and monitoring system records). [8 CAR § 41-204 and 40 CFR 60.5560a(a)]
    a. For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under Subpart F of 40 CFR Part 75. [8 CAR § 41-204 and 40 CFR 60.5560a(b)(1)]
    b. You must keep records of the calculations performed to determine the hourly and total CO_2 mass emissions (tons) for each operating month and each compliance period, including, each 12-operating-month compliance period. Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output. [8 CAR § 41-204 and 40 CFR 60.5560a(c)-(d)]

c. You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period. You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 of this subpart. [8 CAR § 41-204 and 40 CFR 60.5560a(e)-(f)]

d. For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory (low or intermediate load classification). [8 CAR § 41-204 and 40 CFR 60.5560a(h)]

Fugitive Emissions from Piping Components (SN-17 through SN-19)

130. The permittee shall not exceed the following limits on equipment components for each type of piping, for each material in service. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

SN	Material Service	Component Type	Max # of Components
17 (IPS-NGFUG)	Natural Gas	Valves	400
		Flanges	1000
		Relief Valves	7
		Open-Ended Lines	80
		Sampling Connections (hourly)	2
		Sampling Connections (annually)	2190
18 (IPS-AMMFUG)	Ammonia	Valves	300
		Pumps	2
		Flanges	200
		Relief Valves	4
		Open-Ended Lines	4
19 (IPS-DSLFUG)	Diesel Fuel	Valves	40
		Flanges	60
		Open-Ended Lines	10

131. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #130. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The calendar year totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

132. The permittee will employ AVO (Audio-Visual-Olfactory) monitoring as BACT for SN-17, 18, and 19. During normal work activities, employees will be directed to immediately alert operations anytime a leak is detected by sight, sound, or smell. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]
   a. All piping components shall be inspected by AVO means at least weekly by operating personnel walk-through.
   b. Immediately, but no later than one hour upon detection of a leak, personnel shall take at least one of the following actions:
      i. Isolate the leak.
      ii. Commence repair or replacement of the leaking component.
      iii. Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.
   c. Damaged or leaking valves, connectors, compressor seals, and pump seals found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging.
   d. The date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to AVO-detected leaks.
   e. Affected operating staff shall receive annual refresher training on the AVO leak detection and repair program.

Unit IPS Only

SN-12
Emergency Standby Generator Engine

Source Description

SN-12 is an emergency diesel-fired IC rated at 2,180 kW (EPN: IPS-EMGEN / SN-12). The engine is a Mitsubishi Model S16R-Y2PTAW2-1 with a 2,923 bhp rating. The emergency standby generator is a USEPA-certified Tier 2 engine. Because this engine will not be operational until the LC4 unit and its associated equipment have been removed from service, the facility will cease to be a major source of HAP and the unit will be an emergency engine at an area source.

Specific Conditions

133. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #138. [8 CAR § 41-801 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	Tpy
12	IPS-EMGEN	Emergency Standby Generator Engine 2,923 bhp, diesel-fired, MMBtu/hr max	PM PM_{10} $PM_{2.5}$ VOC CO CO_2e	1.0 1.0 1.0 2.7 16.9 206.3	0.3 0.3 0.3 0.7 4.3 904.0

134. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #138. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
12	IPS-EMGEN	Emergency Standby Generator Engine 2,923 bhp, diesel-fired, MMBtu/hr max	SO_2 NO_x	0.1 30.8	0.1 7.7

135. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #138. [8 CAR § 40-701 and Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
12	Emergency Standby Generator Engine 2,923 bhp, diesel-fired, MMBtu/hr max	Total HAP	0.04	0.01

136. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
12	20%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E

137. Annual observations of the opacity from SN-12 shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated annually, kept on site, and made available to Division of Environmental Quality personnel upon request.

a. The date and time of the observation.
b. If visible emissions which appeared to be above the permitted limit were detected.
c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
d. The name of the person conducting the opacity observations.

[8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

138. The permittee shall not operate the emergency generator SN-12 in excess of 500 total hours (emergency and non-emergency) per calendar year in order to demonstrate compliance with the annual emission rate limits. Emergency operation in excess of these hours may be allowable but shall be reported and will be evaluated in accordance with 8 CAR § 41-502 and other applicable rules. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

139. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #138. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The calendar year totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

NSPS IIII Requirements (SN-12)

140. The emergency generator engine (SN-12) is subject to 40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This unit is classified as a new compression-ignition (CI) emergency engine at a major source. [8 CAR § 41-204 and 40 C.F.R. § 63.6590(b)(3)(iii)]

141. SN-12 is subject to 40 C.F.R. § 60 Subpart IIII. The permittee shall comply with all applicable provisions of 40 C.F.R. § 60 Subpart IIII which includes, but is not limited to, Specific Conditions #2 through #18. [8 CAR § 41-204 and 40 C.F.R. § 60 Subpart IIII]

142. The provisions of 40 C.F.R. § 60 Subpart IIII are applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the stationary CI ICE are manufactured after April 1, 2006, and are not fire pump engines. For the purposes of 40 C.F.R. § 60 Subpart IIII, the date that construction commences is the date the engine is ordered by the owner or operator. [8 CAR § 41-204 and 40 C.F.R. § 60.4200(a)(2)(i)]

143. Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. [8 CAR § 41-204 and 40 C.F.R. § 60.4205(b)]

Rated Power (kW)	Starting Model Year	NOx +NMOC g/kW-hr	CO g/kW-hr	PM g/kW-hr
kW>560	2005	6.4	3.5	0.2

144. The permittee must operate and maintain stationary CI ICE that achieve the emission standards as required in § 60.4205 over the entire life of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4206]

145. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to 40 C.F.R. § 60 Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 C.F.R. § 80.510(b) for nonroad diesel fuel. [8 CAR § 41-204 and 40 C.F.R. § 60.4207(b)]

146. If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(a)]

147. If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(b)]

148. If you are an owner or operator and must comply with the emission standards specified in 40 C.F.R. § 60 Subpart IIII, you must do all of the following, except as permitted under § 60.4211(g): [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)]
    a. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(1)]
    b. Change only those emission-related settings that are permitted by the manufacturer; and [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(2)]
    c. Meet the requirements of 40 C.F.R. §§ 89, 94 and/or 1068, as they apply to you. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(a)(3)]

149. If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to 40 C.F.R. § 60 Subpart IIII and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in § 60.4211(g). [8 CAR § 41-204 and 40 C.F.R. § 60.4211(c)]

150. The emergency generator engine (SN-12) must be operated in accordance with the requirements in paragraphs (f)(1) through (4) of 40 CFR §63.6640 (outlined in (a) through (d) of this condition). In order for the engine to be considered an emergency stationary RICE under Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of 40 CFR §63.6640 is prohibited. If SN-12 is not operated according to the requirements of paragraphs (f)(1) through (4) of 40 CFR §63.6640, the engine will not be considered an emergency engine under subpart ZZZZ and must meet all requirements for non-emergency engines. [8 CAR § 41-204 and 40 C.F.R. § 63.6640]

a. There is no time limit on the use of SN-12 in emergency situations.
    i. SN-12 may be operated for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).
    ii. SN-12 may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, the regional transmission operator, or the insurance company associated with the engine. The owner or operator may petition the administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.
b. SN-12 may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) or 40 CFR §63.6640. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial agreement with another entity.
   [8 CAR § 41-204 and 40 C.F.R. § 60.4211(f)(3)(i)(E)]

151. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows: [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)]
   a. If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards. [8 CAR § 41-204 and 40 C.F.R. § 60.4211(g)(3)]

152. The permittee is not required to submit an initial notification. Starting with the model years in the table below, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(b) and Table 5 to 40 C.F.R. § 60 Subpart IIII]

Engine power	**Starting model year**
KW≥130 (HP≥175)	2011

153. If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached. [8 CAR § 41-204 and 40 C.F.R. § 60.4214(c)]

154. Table 8 to 40 C.F.R. § 60 Subpart IIII shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you. [8 CAR § 41-204 and 40 C.F.R. § 60.4218]

NESHAP ZZZZ Requirements (SN-12)

155. The emergency generator engine (SN-12) is subject to 40 CFR § 63 Subpart ZZZZ – *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. This unit is classified as a new stationary RICE at an area source of HAP, where the RICE is also subject to 40 C.F.R. § 60 Subpart IIII. As such, it complies with 40 C.F.R. § 63 Subpart ZZZZ by complying with 40 C.F.R. § 60 Subpart IIII. No further requirements apply for such engines under 40 C.F.R. § 63 Subpart ZZZZ. [8 CAR § 41-204 and 40 C.F.R. § 63.6590(c)(1)]

Unit IPS Only

SN-13
Diesel Emergency Fire Water Pump

Source Description

SN-13 is an emergency diesel-fired IC engine powers, rated at 235 kW (EPN: IPS-FWP / SN-13). The engine is a John Deere Model 6068HFC48A with a 282 BHP rating. The engine will only fire ULSD with a maximum sulfur content of 15 ppmw. The emergency fire water pump is a USEPA-certified Tier 3 engine. Because this engine will not be operational until the LC4 unit and its associated equipment have been removed from service, the facility will cease to be a major source of HAP and the unit will be an emergency engine at an area source.

Specific Conditions

156. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #161. [8 CAR § 41-801 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
13	IPS-FWP	Diesel Emergency Fire Water Pump 282 hp, diesel-fired, 1.89 MMBtu/hr	PM PM_{10} $PM_{2.5}$ VOC CO CO_2e	0.2 0.2 0.2 0.1 1.9 17.7	0.1 0.1 0.1 0.1 0.5 77.4

157. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #161. [8 CAR § 40-401 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
13	IPS-FWP	Diesel Emergency Fire Water Pump 282 hp, diesel-fired, 1.89 MMBtu/hr	SO_2 NO_x	0.1 2.1	0.1 0.6

158. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition through compliance with Specific Condition #161. [8 CAR § 40-701 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
13	IPS-FWP	Diesel Emergency Fire Water Pump 282 hp, diesel-fired, 1.89 MMBtu/hr	Total HAP	0.01	0.01

159. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9.

SN	Limit	Regulatory Citation
13	20%	8 CAR § 41-403 and 40 C.F.R. § 52 Subpart E

160. Annual observations of the opacity from SN-13 shall be conducted by a person trained but not necessarily certified in EPA Reference Method 9. If visible emissions in excess of the permitted levels are detected, the permittee shall immediately take action to identify the cause of the visible emissions in excess of the permit limit, implement corrective action, and document that visible emissions did not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this specific condition. These records shall be updated annually, kept on site, and made available to Division of Environmental Quality personnel upon request.
    a. The date and time of the observation.
    b. If visible emissions which appeared to be above the permitted limit were detected.
    c. If visible emissions which appeared to be above the permitted limit were detected, the cause of the exceedance of the opacity limit, the corrective action taken, and if the visible emissions appeared to be below the permitted limit after the corrective action was taken.
    d. The name of the person conducting the opacity observations.

[8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

161. The permittee shall not operate the emergency generator SN-13 in excess of 500 total hours (emergency and non-emergency) per calendar year in order to demonstrate compliance with the annual emission rate limits. Emergency operation in excess of these hours may be allowable but shall be reported and will be evaluated in accordance with 8 CAR § 41-502 and other applicable rules. [8 CAR § 41-605, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

162. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #161. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The calendar year totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [8 CAR § 41-605 and 40 C.F.R. § 52 Subpart E]

NSPS IIII Requirements (SN-13)

163. The emergency fire pump (SN-13) is subject to 40 C.F.R. § 60 Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines,* as a new stationary compression-ignition RICE fire pump with a displacement of less than 30 liters displacement per cylinder. The permittee shall comply with Specific Conditions #164 through 170. [8 CAR § 41-204 and 40 C.F.R. § 60 Subpart IIII]

164. The permittee must comply with the emission standards in the table below [Table 4 to 40 C.F.R. § 60 Subpart IIII] for all pollutants. [8 CAR § 41-204 and 40 C.F.R. § 63.4205(c)]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450	2009 +	4.0 g/kW-hr	3.5 g/kW-hr	0.20 g/kW-hr

165. The permittee must demonstrate compliance by purchasing an engine certified to the emission standards in §60.4205(c) for the same model year and NFPA nameplate engine power.
    a. The permittee must operate and maintain the engine that achieves the emission standards as required in § 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.
    b. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in §60.4211(g)(2).

    [8 CAR § 41-204 and 40 C.F.R. § 60.4206, §60.4211(c), and §60.4211(g)(2)]

166. The permittee must use diesel fuel that meets the requirements of 40 C.F.R. § 1090.305 for nonroad diesel fuel, a maximum sulfur content of 15 ppm. [8 CAR § 41-204 and 40 C.F.R. § 60.4207 (b) and § 1090.305(b)]

167. The permittee must install a non-resettable hour meter prior to startup of the engine. [8 CAR § 41-204 and 40 C.F.R. § 60.4209(a)]

168. The permittee must operate and maintain the engine and any control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, except as described below.
    a. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:
        i. The permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.
        ii. The permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after the permittee changes emission-related settings in a way that is not permitted by the manufacturer.
    b. Otherwise, the permittee may only change those settings that are permitted by the manufacturer.
    c. The permittee must also meet the requirements of 40 C.F.R. parts 89, 94 and/or 1068 as they apply to the engine.

[8 CAR § 41-204 and 40 C.F.R. § 60.4211(a) and § 60.4211(g)(2)]

169. The permittee is not required to submit an initial notification. Starting with the model years in the table below, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

Engine power	Starting model year
KW≥130 (HP≥175)	2011

[8 CAR § 41-204 and 40 C.F.R. § 60.4214(b)]

170. The permittee must operate the emergency stationary ICE according to the requirements in this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in this section, is prohibited. If you do not operate the engine according to the requirements in this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.
   a. There is no time limit on the use of emergency stationary ICE in emergency situations.
   b. The permittee may operate the emergency stationary ICE for any combination of the purposes specified in this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by this section counts as part of the 100 hours per calendar year allowed by this paragraph.
      i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.
   c. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (b) of this section. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response.

   [8 CAR § 41-204 and 40 C.F.R. § 60.4211 (f)(1)(2)(i)(3)]

NESHAP ZZZZ Requirements (SN-13)

171. The emergency fire pump (SN-13) is subject to 40 C.F.R. § 63 Subpart ZZZZ – *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. This unit is classified as a new stationary RICE at an area source of HAP, where the RICE is also subject to 40 C.F.R. § 60 Subpart IIII. As such, it complies with 40 C.F.R. § 63 Subpart ZZZZ by complying with 40 C.F.R. § 60 Subpart IIII. No further requirements apply for such engines under 40 C.F.R. § 63 Subpart ZZZZ. [8 CAR § 41-204 and 40 C.F.R. § 63.6590(c)(1)]

SN-20, 21
Tanks

Source Description

Entergy proposes to construct two small horizontal fixed-roof diesel storage tanks. Each tank provides ULSD fuel to the two emergency IC engines. The tank that will supply ULSD to the emergency generator will be a 99 bbl (4,150 gal) white, horizontal fixed-roof tank (EPN: IPS-TK1 / SN-20) mounted under the emergency generator frame. The tank that will supply ULSD to the emergency fire water pump will be a 12 bbl (500 gal) white, horizontal fixed-roof tank (EPN: IPS-TK2 / SN-21).

Specific Conditions

172. The permittee shall not exceed the emission rates set forth in the following table. Emissions are based on maximum throughput and turnovers. [8 CAR § 41-801 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Entergy Emission Source ID	Description	Pollutant	lb/hr	tpy
20	IPS-TK1	4,150 gallon ULSD tank for Emergency Engine SN-12	VOC	0.3	0.1
21	IPS-TK2	500 gallon ULSD tank for Fire Water Pump SN-13	VOC	0.1	0.1

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Entergy Arkansas, LLC - Lake Catherine Plant will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future rules and regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [8 CAR § 41-604, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [8 CAR § 41-310(b) and 40 C.F.R. § 52 Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Division of Environmental Quality or within 180 days of permit issuance if no date is specified. The permittee must notify the Division of Environmental Quality of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Division of Environmental Quality within sixty (60) calendar days after completing the testing. [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [8 CAR § 41-602 and/or 8 CAR § 40-902 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [8 CAR § 41-203 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [8 CAR pt. 42 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

7. Unless otherwise specified in the permit, approval to construct any new major stationary source or a major modification subject to 40 C.F.R. § 52.21 shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Division of Environmental Quality may extend the 18-month period upon a satisfactory showing that an extension is justified. [8 CAR § 41-801 et seq. and 40 C.F.R. § 52 Subpart E]

Acid Rain (Title IV)

8. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [Reg.26.701 and 40 C.F.R. § 70.6(a)(4)]

Title VI Provisions

9. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 C.F.R. § 82 Subpart E]

   a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to § 82.106.
   b. The placement of the required warning statement must comply with the requirements pursuant to § 82.108.
   c. The form of the label bearing the required warning must comply with the requirements pursuant to § 82.110.
   d. No person may modify, remove, or interfere with the required warning statement except as described in § 82.112.

10. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 C.F.R. § 82 Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to § 82.166. ("MVAC like appliance" as defined at § 82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

11. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 C.F.R. § 82 Subpart A, Production and Consumption Controls.

12. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 C.F.R. § 82 Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

13. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 C.F.R. § 82 Subpart G.

Transport Rule (TR) Trading Program Title V Requirement-LC4 and IPS

14. The permittee shall comply with the following Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program Requirements. The unit-specific monitoring provisions are attached to this Title V permit. [40 C.F.R. § 97 Subpart EEEEE and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

   a. Designated representative requirements.
      The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 C.F.R. §§ 97.813 through 97.818.
   b. Emissions monitoring, reporting, and recordkeeping requirements.
      1. The owners and operators, and the designated representative, of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 C.F.R. §§ 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
      2. The emissions data determined in accordance with 40 C.F.R. §§ 97.830 through 97.835 shall be used to calculate allocations of TR NO_X Ozone Season Group 2 allowances under 40 C.F.R. §§ 97.811(a)(2) and (b) and 97.812 and to determine compliance with the TR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 C.F.R. §§ 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. NO_X emissions requirements.
   1. TR NO_X Ozone Season Group 2 emissions limitation.
      i. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 C.F.R. § 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season Group 2 units at the source.
      ii. If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season Group 2 units at a TR NO_X Ozone Season Group 2 source are in excess of the TR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:
         A. The owners and operators of the source and each TR NO_X Ozone Season Group 2 unit at the source shall hold the TR NO_X Ozone Season Group 2 allowances required for deduction under 40 C.F.R. § 97.824(d); and
         B. The owners and operators of the source and each TR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 C.F.R. § 97 Subpart EEEEE and the Clean Air Act.
   2. TR NO_X Ozone Season Group 2 assurance provisions.
      i. If total NO_X emissions during a control period in a given year from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 C.F.R. § 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 C.F.R. § 97.825(b), of multiplying—

A. The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

B. The amount by which total NO_X emissions from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State for such control period exceed the State assurance level.

ii. The owners and operators shall hold the TR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

iii. Total NO_X emissions from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 C.F.R. § 97.810(a) and the state's variability limit under 40 C.F.R. § 97.810(b).

iv. It shall not be a violation of 40 C.F.R. § 97 Subpart EEEEE or of the Clean Air Act if total NO_X emissions from all base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State during a control period exceed the State assurance level or if a common designated representative's share of total NO_X emissions from the base TR NO_X Ozone Season Group 2 units at base TR NO_X Ozone Season Group 2 sources in the State during a control period exceeds the common designated representative's assurance level.

v. To the extent the owners and operators fail to hold TR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
   A. The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
   B. Each TR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 C.F.R. § 97 Subpart EEEEE and the Clean Air Act.

3. Compliance periods.
   i. A TR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 C.F.R. § 97.830(b) and for each control period thereafter.
   ii. A base TR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 C.F.R. § 97.830(b) and for each control period thereafter.
4. Vintage of TR NO_X Ozone Season Group 2 allowances held for compliance.
   i. A TR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a TR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.
   ii. A TR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a TR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.
5. Allowance Management System requirements. Each TR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 C.F.R. § 97 Subpart EEEEE.

6. Limited authorization. A TR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:
    i. Such authorization shall only be used in accordance with the TR NO_X Ozone Season Group 2 Trading Program; and
    ii. Notwithstanding any other provision of 40 C.F.R. § 97 Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
7. Property right. A TR NO_X Ozone Season Group 2 allowance does not constitute a property right.

d. Title V permit requirements.
    1. No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season Group 2 allowances in accordance with 40 C.F.R. § 97 Subpart EEEEE.
    2. This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 C.F.R. §§ 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 C.F.R. § 75 Subparts B and H), an excepted monitoring system (pursuant to 40 C.F.R. § 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 C.F.R. § 75.19), and an alternative monitoring system (pursuant to 40 C.F.R. § 75 Subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 C.F.R. §§ 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.
    1. Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
        i. The certificate of representation under 40 C.F.R. § 97.816 for the designated representative for the source and each TR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 C.F.R. § 97.816 changing the designated representative.
        ii. All emissions monitoring information, in accordance with 40 C.F.R. § 97 Subpart EEEEE.

iii. Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Group 2 Trading Program.

2. The designated representative of a TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the TR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 C.F.R. § 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 C.F.R. §§ 70 and 71.

f. Liability.

1. Any provision of the TR NO_X Ozone Season Group 2 Trading Program that applies to a TR NO_X Ozone Season Group 2 source or the designated representative of a TR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season Group 2 units at the source.
2. Any provision of the TR NO_X Ozone Season Group 2 Trading Program that applies to a TR NO_X Ozone Season Group 2 unit or the designated representative of a TR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

g. Effect on other authorities.

No provision of the TR NO_X Ozone Season Group 2 Trading Program or exemption under 40 C.F.R. § 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season Group 2 source or TR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

SECTION VII: INSIGNIFICANT ACTIVITIES

The Division of Environmental Quality deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in 8 CAR pt. 40 and pt. 41 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee ins applications dated April 19, 2021, and February 24, 2025. [8 CAR § 42-204 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Description	Category
Lake Catherine Unit #4 Support Equipment (equipment to be used only while LCU4 is in service)	
C8 – Kerosene Fired Steam Heater	A-1
Six (6) 170,000 Btu/hr Diesel-fired Heaters	A-1
T23B – Unit 4 FD Fan LO Reservoir	A-2
T24A – Unit 4 BFW LO Reservoir	A-2
T24B – Unit 4 BFW LO Reservoir	A-2
T24C – Unit 4 BFW LO Reservoir	A-2
T24D – Unit 4 BFW LO Reservoir	A-2
T25 – Unit 4 BFP LO Reservoir	A-2
T27 – Used Oil Storage Tank	A-2
T35 – Used Kerosene Drum	A-2
T37 – Waste Oil/Solvent Storage	A-2
T46 – Oil/Water Separator (Oil Section)	A-2
T21 – Unit 4 LO Filter Tank	A-3
T22 – Unit 4 Seal Oil Tank	A-3
T23A – Unit 4 FD Fan LO Reservoir	A-3
T26 – Emergency Diesel Generator Tank	A-3
T36 – Oil Drum Storage	A-3
T44 – Diesel Tank	A-3

Description	Category
T19 – Unit 4 LO Batch Tanks (2 – 12,000 gal)	A-13
T20 – Unit 4 LO Reservoir (12,000 gal)	A-13
T45 – 300 gallon Gasoline Tank	A-13
X1 – Degreaser	A-13
X2 – Unit 3 Welding Area (1 machine)	A-13
X4 – Diesel Fuel Oil Dispensing Station	A-13
X5 – Unleaded Gasoline Dispensing Station	A-13
X6 – Unit 4 Bead Blaster	A-13
X13 – Aerosol Lubricant Fugitives	A-13
X14 – Aerosol Degreaser Fugitives	A-13
X15 – Aerosol Insecticides	A-13
X18 – Welding Shop (3 machines)	A-13
X19 – Aerosol Puncture Station	A-13

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission 8 CAR pt. 40 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission 8 CAR pt. 40 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission 8 CAR pt. 40 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 C.F.R. § 70.6(a)(2) and 8 CAR § 42-601(2)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Division of Environmental Quality takes final action on the renewal application. The Division of Environmental Quality will not necessarily notify the permittee when the permit renewal application is due. [8 CAR. [8 CAR § 42-306]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 C.F.R. § 70.6(a)(1)(ii) and 8 CAR § 42-601(1)(C)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses performed;
    c. The company or entity performing the analyses;
    d. The analytical techniques or methods used;
    e. The results of such analyses; and
    f. The operating conditions existing at the time of sampling or measurement.

    [40 C.F.R. § 70.6(a)(3)(ii)(A) and 8 CAR § 42-601(3)(C)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 C.F.R. § 70.6(a)(3)(ii)(B) and 8 CAR § 42-601(3)(C)(ii)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in 8 CAR § 42-104 must certify all required reports. The permittee will send the reports electronically using https://eportal.adeq.state.ar.us or mail them to the address below:

   Division of Environmental Quality
   Office of Air Quality
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 C.F.R. § 70.6(a)(3)(iii)(A) and 8 CAR § 42-601(3)(D)(i)]

8. The permittee shall report to the Division of Environmental Quality all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in 8 CAR § 41-501), the permittee will make an initial report to the Division of Environmental Quality by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location;
      ii. The process unit or emission source deviating from the permit limit;
      iii. The permit limit, including the identification of pollutants, from which deviation occurs;
      iv. The date and time the deviation started;
      v. The duration of the deviation;

vi. The emissions during the deviation;
vii. The probable cause of such deviations;
viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Division of Environmental Quality within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[8 CAR § 41-501, 8 CAR § 41-502, 8 CAR § 42-601(3)(D)(ii), and 40 C.F.R. § 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Rule are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Rule 8 CAR § 42-601(5), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in 8 CAR pt. 42 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. § 7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 C.F.R. § 70.6(a)(6)(i) and 8 CAR § 42-601(6)(A)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 C.F.R. § 70.6(a)(6)(ii) and 8 CAR § 42-601(6)(B)]

12. The Division of Environmental Quality may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 C.F.R. § 70.6(a)(6)(iii) and 8 CAR § 42-601(6)(C)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and 8 CAR § 42-601(6)(D)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Division of Environmental Quality may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and 8 CAR § 42-601(6)(E)]

15. The permittee must pay all permit fees in accordance with the procedures established in 8 CAR pt. 12. [40 C.F.R. § 70.6(a)(7) and 8 CAR § 42-601(7)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 C.F.R. § 70.6(a)(8) and 8 CAR § 42-601(8)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 C.F.R. § 70.6(a)(9)(i) and 8 CAR § 42-601(9)(B)(i)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Division of Environmental Quality specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and 8 CAR § 42-602(a) and (b)]

19. Any document (including reports) required by this permit pursuant to 40 C.F.R. § 70 must contain a certification by a responsible official as defined in 8 CAR § 42-104. [40 C.F.R. § 70.6(c)(1) and 8 CAR § 42-603(1)]

20. The permittee must allow an authorized representative of the Division of Environmental Quality, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and 8 CAR § 42-603(2)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
    d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Division of Environmental Quality. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and 8 CAR § 42-603(5)(B)(iii)]

    a. The identification of each term or condition of the permit that is the basis of the certification;
    b. The compliance status;
    c. Whether compliance was continuous or intermittent;
    d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
    e. Such other facts as the Division of Environmental Quality may require elsewhere in this permit or by § 114(a)(3) and § 504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [8 CAR § 42-604(c)]

    a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
    b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
    c. The applicable requirements of the acid rain program, consistent with § 408(a) of the Act; or
    d. The ability of EPA to obtain information from a source pursuant to § 114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion in the following circumstances:

    a. Such an extension does not violate a federal requirement;
    b. The permittee demonstrates the need for the extension; and
    c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

    [8 CAR § 40-214(a), 8 CAR § 41-316(a), 8 CAR § 42-913(a), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Division of Environmental Quality approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

    a. Such a request does not violate a federal requirement;
    b. Such a request is temporary in nature;
    c. Such a request will not result in a condition of air pollution;
    d. The request contains such information necessary for the Division of Environmental Quality to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
    e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
    f. The permittee maintains records of the dates and results of such temporary emissions/testing.

    [8 CAR § 40-214(b), 8 CAR § 41-316(b), 8 CAR § 42-913(b), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Division of Environmental Quality approval. The Division of Environmental Quality may grant such a request, at its discretion under the following conditions:

    a. The request does not violate a federal requirement;
    b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
    c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

    [8 CAR § 40-214(c), 8 CAR § 41-316(c), 8 CAR § 42-913(c), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

27. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [8 CAR. [8 CAR § 40-901, 8 CAR § 41-601, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

APPENDIX A

<table>
<tr><th colspan="5">Maximum Capacity Emission Rates</th></tr>
<tr><th></th><th></th><th></th><th>100%
Natural Gas
(tpy)</th><th>100%
Fuel Oil
(tpy)</th></tr>
<tr><td rowspan="2">01 (C1)</td><td>Unit 1</td><td>PM
PM_{10}
SO_2
VOC
CO
NO_x</td><td>Retired
December
2013</td><td>Retired
December
2013</td></tr>
<tr><td>Unit 2</td><td>PM
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SO_2
VOC
CO
NO_x</td><td>Retired
December
2013</td><td>Retired
December
2013</td></tr>
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SO_2
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CO
NO_x</td><td>Retired
December
2013</td><td>Retired
December
2013</td></tr>
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PM_{10}
SO_2
VOC
CO
NO_x</td><td>194.8
194.8
15.4
141.0
615.0
14861.4</td><td>2113.3
1563.5
11926.3
158.0
759.6
14861.3</td></tr>
</table>

APPENDIX B

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Division of Environmental Quality

Office of Air Quality

12/3/2020

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally, there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 C.F.R. § 60 or 63.
2. CEMS required by 40 C.F.R § 75.
3. CEMS/COMS required by permit for reasons other than § 60, 63 or 75.

These CEMS/COMS conditions are not intended to supersede 40 C.F.R. § 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by the Arkansas Department of Energy and Environment's (Department) Division of Environmental Quality (DEQ) permit for reasons other than 40 C.F.R. § 60, 63 or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.
- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) – The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) – The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) – The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) – A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions – Any period in which the emissions exceed the permit limits.

Monitor Downtime – Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period – Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the Relative Accuracy Test Audit (RATA), Relative Accuracy Audit (RAA), or Cylinder Gas Audit (CGA) which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS – The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) – The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

** Only CEMS/COMS required by DEQ permit for reasons other than 40 C.F.R. § 60, 63 or 75 shall comply with this section.

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 C.F.R. § 60, Appendix B, PS 1-9. DEQ may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the DEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 C.F.R, § 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval, the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen-minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one-hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the DEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

** All CEMS/COMS shall comply with this section.

A. When requested to do so by an owner or operator, the DEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the DEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 business days prior to testing. Performance test results shall be submitted to DEQ within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to DEQ (Attention: DEQ, Office of Air Quality, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on DEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from DEQ.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Quarterly reports shall be used by DEQ to determine compliance with the permit.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

** Only CEMS/COMS required by DEQ permit for reasons other than 40 C.F.R. § 60, 63 or 75 shall comply with this section.

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to DEQ (Attn.: DEQ, Office of Air Quality, CEM Coordinator). CEMS quality assurance procedures are defined in 40 C.F.R. § 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from DEQ.

C. Facilities responsible for one or more CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
    a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked, and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
    a. Out-of-control period determination
    b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
    a. CEMS/COMS information
        1) Manufacture
        2) Model number
        3) Serial number
    b. Scheduled activities (check list)
    c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA) shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 C.F.R. § 60 Appendix A and calculated in accordance with the applicable performance specification in 40 C.F.R. § 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 C.F.R. § 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the DEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O_2 or CO_2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three-run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three-run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 C.F.R. § 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze, and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

APPENDIX C

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☑ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Lake Catherine Plant	AR	170

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
4	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Lake Catherine Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name David Triplett	
Signature	Date 3/11/2021

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the Title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the Title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the Title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the Title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a Title V permit, or such longer time as provided for under the Title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate Title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Clean Air Markets Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☒ revised ☐ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Lake Catherine	AR	170

Note: Entergy Arkansas, LLC is shutting down existing Unit 4 and starting up a new Unit 5 on or about January 1, 2029.

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
5	Yes

Facility (Source) Name (from STEP 1) Lake Catherine

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
- (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
- (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
- (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
- (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
- (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
- (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
- (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
- (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Facility (Source) Name (from STEP 1) Lake Catherine

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
 (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
 (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
 (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
 (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Facility (Source) Name (from STEP 1) Lake Catherine

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Louise Duncan - Vice President - Power Plant Operations - Arkansas	
Signature	Date 01-23-2024

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the Title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the Title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the Title V permitting authority.

STEP 1 A Plant Code is a 4- or 5-digit number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the Title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a Title V permit, or such longer time as provided for under the Title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate Title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Clean Air Markets Hotline at (202) 343-9620.

Paperwork Burden Estimate

This collection of information is approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. (OMB Control No. 2060-0258). Responses to this collection of information are mandatory (40 CFR 72.30 and 72.31). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The public reporting and recordkeeping burden for this collection of information is estimated to be 8 hours per response. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the Regulatory Support Division Director, U.S. Environmental Protection Agency (2821T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

APPENDIX D

Transport Rule (TR) NO_X Ozone Season Trading Program Requirements

1. The permittee shall comply with the following TR NO_X Ozone Season Trading Program Requirements. The unit-specific monitoring provisions are attached to this Title V permit. [40 C.F.R. § 97 Subpart BBBBB and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

   a. Designated representative requirements.
      The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 C.F.R. §§ 97.513 through 97.518.
   b. Emissions monitoring, reporting, and recordkeeping requirements.
      1. The owners and operators, and the designated representative, of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 C.F.R. §§ 97.530 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.531 (initial monitoring system certification and recertification procedures), 97.532 (monitoring system out-of-control periods), 97.533 (notifications concerning monitoring), 97.534 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.535 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
      2. The emissions data determined in accordance with 40 C.F.R. §§ 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under 40 C.F.R. §§ 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 C.F.R. §§ 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.
   c. NO_X emissions requirements.
      1. TR NO_X Ozone Season emissions limitation.
         i. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under 40 C.F.R. § 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

ii. If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source are in excess of the TR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(i) above, then:
   A. The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under 40 C.F.R. § 97.524(d); and
   B. The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 C.F.R. § 97 Subpart BBBBB and the Clean Air Act.

2. TR NO_X Ozone Season assurance provisions.
   i. If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season allowances available for deduction for such control period under 40 C.F.R. § 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 C.F.R. § 97.525(b), of multiplying—
      A. The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and
      B. The amount by which total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state for such control period exceed the state assurance level.
   ii. The owners and operators shall hold the TR NO_X Ozone Season allowances required under paragraph (c)(2)(i) above, as of

APPENDIX E

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

§ 60.4216 What requirements must I meet for engines used in Alaska?

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

General Provisions

§ 60.4218 What General Provisions and confidential information provisions apply to me?

Definitions

§ 60.4219 What definitions apply to this subpart?

Table 1 to Subpart IIII of Part 60

Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

Table 2 to Subpart IIII of Part 60

Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

Table 3 to Subpart IIII of Part 60

Certification Requirements for Stationary Fire Pump Engines

Table 4 to Subpart IIII of Part 60

Emission Standards for Stationary Fire Pump Engines

Table 5 to Subpart IIII of Part 60

Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

Table 6 to Subpart IIII of Part 60

Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

Table 7 to Subpart IIII of Part 60

Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

Table 8 to Subpart IIII of Part 60

Applicability of General Provisions to Subpart IIII

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C, except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 86 FR 34357, June 29, 2021]

EMISSION STANDARDS FOR MANUFACTURERS

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 1039.102, 1039.104, 1039.105, 1039.107, and 1039.115 and 40 CFR part 1039, appendix I, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34357, June 29, 2021]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The Tier 2 emission standards for new nonroad CI engines for the appropriate rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 for model year 2007 engines; and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section. Engines that would be subject to the Tier 4 standards in 40 CFR part 1042 that are used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section may instead continue to be certified to the previous tier of standards in 40 CFR part 1042. The previous tier is Tier 3 in most cases; however, the previous tier is Tier 2 if there are no Tier 3 standards specified for engines of a certain size or power rating.

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021; 88 FR 4471, Jan. 24, 2023]

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

EMISSION STANDARDS FOR OWNERS AND OPERATORS

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 86 FR 34358, June 29, 2021]

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) [Reserved]

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 85 FR 78463, Dec. 4, 2020]

OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

COMPLIANCE REQUIREMENTS

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §§ 60.4201(a) through (c) and 60.4202(a), (b), and (d) using the certification procedures required in 40 CFR part 1039, subpart C, and must test their engines as specified in 40 CFR part 1039. For the purposes of this subpart, engines certified to the standards in Table 1 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I. For the purposes of this subpart, engines certified to the standards in Table 4 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §§ 60.4201(d) and (e) and 60.4202(e) and (f) using the certification procedures required in 40 CFR part 1042, subpart C, and must test their engines as specified in 40 CFR part 1042.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135 and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking, and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of § 60.4201 or § 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all the requirements in 40 CFR 1039.665 that apply to manufacturers.

Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR part 1039, appendix I, when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

(k) Manufacturers of any size may certify their emergency stationary CI internal combustion engines under this section using assigned deterioration factors established by EPA, consistent with 40 CFR 1039.240 and 1042.240.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR part 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(a) or § 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified to emission standards for the same model year and maximum engine power as described in 40 CFR parts 1039 and 1042, as applicable. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021; 87 FR 48605, Aug. 10, 2022]

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2 emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in § 60.4213, as appropriate.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or Tier 2 emission standards as described in 40 CFR part 1042, appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR part 1039 or 1042, as applicable.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011; 86 FR 34359, June 29, 2021]

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section. Beginning on February 26, 2025, submit the notification electronically according to paragraph (g) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

(f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (f)(1) and (2) of this section.

(1) ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to paragraph (g) of this section. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to paragraph (g) of this section.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the

EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 87 FR 48606, Aug. 10, 2022; 89 FR 70512, Aug. 30, 2024]

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§ 60.4202 and 60.4205, and not those for non-emergency engines in §§ 60.4201 and 60.4204, except that for 2014 model year and later nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§ 60.4218 What General Provisions and confidential information provisions apply to me?

(a) Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply for engine manufacturers. For others, the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

[88 FR 4471, Jan. 24, 2023]

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 1042.101(e).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34360, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
(HP<11)					
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1] *Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.*

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	Emission standards for stationary fire pump engines in g/KW-hr (g/HP-hr)		
		$NMHC + NO_X$	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
KW<8 (HP<11)	2011 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
8≤KW<19 (11≤HP<25)	2011 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	2011 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
37≤KW<56 (50≤HP<75)	2011 + [1]	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
56≤KW<75 (75≤HP<100)	2011 + [1]	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
75≤KW<130 (100≤HP<175)	2010 + [2]	4.0 (3.0)	5.0 (3.7)	0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
130≤KW<225 (175≤HP<300)	2009 + [3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
225≤KW<450	2008 and	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Maximum engine power	Model year(s)	Emission standards for stationary fire pump engines in g/KW-hr (g/HP-hr)		
		NMHC + NO_X	CO	PM
(300≤HP<600)	earlier			
225≤KW<450 (300≤HP<600)	2009 + [3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)	2009 +	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
KW>560 (HP>750)	2008 +	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

[89 FR 70513, Aug. 30, 2024]

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[YOU MUST COMPLY WITH THE LABELING REQUIREMENTS IN § 60.4210(F) AND THE RECORDKEEPING REQUIREMENTS IN § 60.4214(B) FOR NEW EMERGENCY STATIONARY CI ICE BEGINNING IN THE FOLLOWING MODEL YEARS:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed [1]	Torque (percent) [2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] *Engine speed: ±2 percent of point.*

[2] *Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.*

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/ location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification

Each	Complying with the requirement to	You must	Using	According to the following requirements
				testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion	i. Select the sampling port location and number/ location of traverse		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3

Each	Complying with the requirement to	You must	Using	According to the following requirements
	engine exhaust.	points at the exhaust of the stationary internal combustion engine;		traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of	(3) Method 7E of 40 CFR part 60,	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the

Each	Complying with the requirement to	You must	Using	According to the following requirements
		the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the	i. Select the	(1) Method 1	(a) If using a control device, the

Each	Complying with the requirement to	You must	Using	According to the following requirements
	concentration of PM in the stationary CI internal combustion engine exhaust	sampling port location and the number of traverse points;	or 1A of 40 CFR part 60, appendix A-1	sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
	requirements		

APPENDIX F

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart KKKKa Standards of Performance for Stationary Combustion Turbines

Introduction

§ 60.4300a What is the purpose of this subpart?

Applicability

§ 60.4305a Does this subpart apply to my stationary combustion turbine?

§ 60.4310a What stationary combustion turbines are not subject to this subpart?

Emission Standards

§ 60.4315a What pollutants are regulated by this subpart?

§ 60.4320a What NO_X emissions standard must I meet?

§ 60.4325a What emission limit must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

§ 60.4330a What SO_2 emissions standard must I meet?

§ 60.4331a What are the requirements for operating a stationary temporary combustion turbine?

General Compliance Requirements

§ 60.4333a What are my general requirements for complying with this subpart?

Monitoring

§ 60.4335a How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I use water or steam injection?

§ 60.4340a How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I do not use water or steam injection?

§ 60.4342a How do I monitor NO_X control operating parameters?

§ 60.4345a How do I demonstrate compliance with my NO_X emissions standard using a NO_X CEMS?

§ 60.4350a How do I use the NO_X CEMS data to determine excess emissions?

§ 60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?

§ 60.4370a How frequently must I determine the fuel sulfur content?

§ 60.4372a How can I demonstrate compliance with my SO_2 emissions standard using records of the fuel sulfur content?

§ 60.4374a How do I demonstrate compliance with my SO_2 emissions standard and determine

excess emissions using a SO_2 CEMS?
Recordkeeping and Reporting
§ 60.4375a What reports must I submit?
§ 60.4380a How are NO_X excess emissions and monitor downtime reported?
§ 60.4385a How are SO_2 excess emissions and monitor downtime reported?
§ 60.4390a What records must I maintain?
§ 60.4395a When must I submit my reports?
Performance Tests
§ 60.4400a How do I conduct performance tests to demonstrate compliance with my NO_X emissions standard if I do not have a NO_X CEMS?
§ 60.4405a How do I conduct a performance test if I use a NO_X CEMS?
§ 60.4415a How do I conduct performance tests to demonstrate compliance with my SO_2 emissions standard?
Other Requirements and Information
§ 60.4416a What parts of the general provisions apply to my affected EGU?
§ 60.4417a Who implements and enforces this subpart?
§ 60.4420a What definitions apply to this subpart?
Table 1 to Subpart KKKKa of Part 60
Nitrogen Oxide Emission Standards for Stationary Combustion Turbines
Table 2 to Subpart KKKKa of Part 60
Alternative Mass-Based NO_X Emission Standards for Stationary Combustion Turbines
Table 3 to Subpart KKKKa of Part 60
Applicability of Subpart A of This Part to This Subpart

Subpart KKKKa—Standards of Performance for Stationary Combustion Turbines

Source: 91 FR 1985, Jan. 15, 2026, unless otherwise noted.

INTRODUCTION

§ 60.4300a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after December 13, 2024.

APPLICABILITY

§ 60.4305a Does this subpart apply to my stationary combustion turbine?

(a) Except as provided for in § 60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG and duct burner(s) that are associated with a combustion turbine subject to this subpart.

(b) A stationary combustion turbine subject to this subpart is not subject to subpart GG or KKKK of this part.

(c) Duct burners are not subject to subpart D, Da, Db, or Dc of this part (as applicable) if the duct burner is used with a HRSG unit that is part of a combustion turbine that is subject to this subpart.

(d) If you own or operate a stationary combustion turbine (including a combined cycle combustion turbine or a CHP combustion turbine) that commenced construction, modification, or reconstruction on or before December 13, 2024, you may submit a written petition to the Administrator requesting that the stationary combustion turbine comply with the applicable requirements for modified units under this subpart as an alternative to complying with subpart GG or KKKK of this part, and with subparts D, Da, Db, and Dc of this part, as applicable. If the Administrator or delegated authority approves the petitioner's request, the affected facility must comply with the requirements for modified units under this subpart unless the stationary combustion turbine is reconstructed or replaced with a new facility in the future.

(e) If you own or operate a combined cycle combustion turbine or combined heat and power combustion turbine, and changes are made after December 13, 2024, to allow the existing combustion turbine to also operate in simple cycle mode and those changes are determined a modification for NSPS purposes, this subpart shall apply to the combustion turbine only as it operates in simple cycle mode, and not to its existing configuration in combined cycle mode.

§ 60.4310a What stationary combustion turbines are not subject to this subpart?

(a) An integrated gasification combined cycle electric utility steam generating unit subject to subpart Da of this part is not subject to this subpart.

(b) A stationary combustion turbine used in a combustion turbine test cell/stand, as defined in § 60.4420a, is not subject to this subpart.

(c) If any solid fuel is combusted in the HRSG, the HRSG is not subject to this subpart.

(d) Stationary gas turbines subject to title II of the Clean Air Act are not subject to this subpart.

Emission Standards

§ 60.4315a What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320a What NO_X emissions standard must I meet?

(a) Except as provided for in paragraph (c) of this section, for each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO_X that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of this section. If you choose to use NO_X CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis and output-based emission rates and standards are determined on a 30-operating-day rolling basis. Mass-based emission rates are determined on both a 4-operating-hour and 12-calendar-month rolling basis.

(b) For the purpose of determining compliance with the applicable emissions standard, you must also meet the requirements specified in paragraphs (b)(1) through (4) of this section, as applicable to your affected facility.

(1) The NO_X emission standard that is applicable to your affected facility shall be determined on an operating-hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of this section. Determining the hourly NO_X emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390a. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour.

(2) As an alternative to the requirements specified in paragraph (b)(1) of this section, you may elect to use the lowest NO_X emission standard that is applicable to your affected facility, as determined using table 1 to this subpart, for the entire required compliance period.

(3) During each operating hour when only natural gas is combusted, you must meet the NO_X emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing natural gas for that operating hour. During each operating hour when the heat input (based on the HHV of the fuels) of the combustion turbine engine is less than 50 percent natural gas (*i.e.,* 50 percent or greater non-natural gas), as defined in § 60.4420a, at any point during an operating hour, you must meet the NO_X emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing fuels other than natural gas for that operating hour. During each operating hour when the heat input to the combustion turbine engine is greater than 50 percent natural gas, as defined in § 60.4420a, during an entire operating hour while combusting some portion of non-natural gas fuels, you must meet the NO_X emission standard as determined by prorating the applicable NO_X standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

(4) If you have two or more combustion turbine engines share a common stack, are connected to a single electric generator, or share a steam turbine, except as provided for in paragraph (b)(4)(i) of this section, you must monitor the hourly NO_X emissions at the common stack in lieu of monitoring each combustion turbine separately. If you choose to comply with the output-based emissions standard, the hourly gross or net energy output (electric, thermal, or mechanical, as applicable) must be the sum of the hourly loads for the individual affected combustion turbines, and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain

compliance with the most stringent applicable emission standard in table 1 or 2 to this subpart, as applicable, at the common stack, each affected combustion turbine sharing the stack is in compliance.

(i) As an alternative to the requirements in this paragraph (b)(4), you may either:

(A) Monitor each combustion turbine separately by measuring the NO_X emissions prior to mixing in the common stack; or

(B) Apportion the NO_X emissions based on the unit's heat input contribution to the total heat input associated with the common stack and the appropriate F-factors. If you chose to comply with the output-based standard, output from a common steam turbine shall be apportioned based on the heat input to each combustion turbine. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the NO_X emissions. The Administrator may approve such alternate methods for apportioning the NO_X emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(ii) [Reserved]

(c) Stationary combustion turbines that meet at least one of the specifications described in paragraphs (c)(1) through (4) of this section are exempt from the applicable NO_X emission standard in paragraphs (a) and (b) of this section.

(1) An emergency combustion turbine, as defined in § 60.4420a;

(2) A stationary combustion turbine that, as determined by the Administrator or delegated authority, is used for the research and development of control techniques and/or efficiency improvements relevant to stationary combustion turbine emissions; or

(3) A stationary combustion turbine that combusts byproduct fuels for which a facility-specific NO_X emissions standard has been established by the Administrator or delegated authority according to the requirements of paragraphs (c)(3)(i) and (ii) of this section is exempt from the emission limits specified in tables 1 and 2 to this subpart.

(i) You may request a facility-specific NO_X emission standard by submitting a written request to the Administrator or delegated authority explaining why your affected facility, when combusting the byproduct fuel, is unable to comply with the applicable NO_X emission standard determined using table 1 or 2 to this subpart.

(ii) If the Administrator or delegated authority approves the request, a facility-specific NO_X emissions standard will be established in a manner that the Administrator or delegated authority determines to be consistent with minimizing NO_X emissions.

(4) Military combustion turbines for use in other than a garrison facility and military combustion turbines installed for use as military training facilities.

(d) You must meet the applicable NO_X emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction).

§ 60.4325a What emission limit must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in table 1 or 2 to this subpart. If your turbine operates below 70 percent of the base load rating at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your stationary combustion turbine's heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, your combustion turbine must meet the corresponding limit for non-natural gas. For non-part load operating hours when your total heat input is greater than 50 percent natural gas while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable NO_X standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

§ 60.4330a What SO_2 emissions standard must I meet?

(a) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or

(2) 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

(b) For each new, modified, or reconstructed stationary combustion turbine combusting 50 percent or more low-Btu gas per calendar month based on total heat input (using the HHV of the fuel), you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 650 milligrams of sulfur per standard cubic meter (mg/scm) (28 grains (gr) of sulfur per 100 standard cubic feet (scf)); or

(2) 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(c) For each new, modified, or reconstructed stationary combustion turbine located in a noncontinental area, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

(d) For each new, modified, or reconstructed stationary combustion turbine for which the Administrator determines that the affected facility does not have access to natural gas and that the removal of sulfur compounds from the fuel would cause more environmental harm than benefit, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

(e) A stationary combustion turbine subject to either subpart J or Ja of this part is not subject to the SO_2 performance standards in this subpart.

§ 60.4331a What are the requirements for operating a stationary temporary combustion turbine?

(a) Notwithstanding any other provision of this subpart, you may operate a small- or medium-size stationary combustion turbine (*i.e.,* a combustion turbine with a base load rating less than or equal to 850 MMBtu/h) at a single location for up to 24 consecutive months, so long as you comply with all of the requirements in paragraphs (b) through (e) of this section.

(b) You must meet the NO_X emissions standard for stationary temporary combustion turbines in table 1 to this subpart and the applicable SO_2 emissions standard in § 60.4330a.

(c) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the NO_X emissions standard must be demonstrated through maintaining the documentation in paragraphs (c)(1) and (2) of this section on-site:

(1) Each stationary temporary combustion turbine in use at the location has a manufacturer's emissions guarantee at or below the full load NO_X emissions standard in table 1 to this subpart; and

(2) Each such turbine has been performance tested at least once in the prior 5 years as meeting the NO_X emissions standard in table 1 to this subpart.

(d) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the SO_2 emissions standard must be demonstrated through complying with the provisions in § 60.4372a.

(e) The conditions in paragraphs (e)(1) through (3) of this section apply in determining whether your stationary combustion turbine qualifies as a stationary temporary combustion turbine.

(1) The turbine may only be located at the same stationary source (or group of stationary sources located within a contiguous area and under common control) for a total period of 24 consecutive months. This is the total period of residence time allowed after the turbine commences operation at the location, regardless of whether the turbine is in operation for the entire 24 consecutive month period.

(2) Any temporary combustion turbine that replaces a temporary combustion turbine at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The relocation of a stationary temporary combustion turbine within a single stationary source (or group of stationary sources located within a contiguous area and under common control) while performing the same or similar function (*i.e.,* serving the same electric, mechanical, or thermal load) does not restart the 24-calendar month residence time period.

GENERAL COMPLIANCE REQUIREMENTS

§ 60.4333a What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.

(b) If you own or operate a stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. Thereafter, unless you perform continuous monitoring consistent with § 60.4335a, § 60.4340a, or § 60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (6) of this section.

(1) Except as provided for in paragraphs (b)(2) through (5) of this section, you must conduct subsequent performance tests within 12 calendar months of the date that the previous performance test was conducted.

(2) If the NO_X emission result from the most recent performance test is less than or equal to 75 percent of the NO_X emissions standard for the stationary combustion turbine, you may reduce the frequency of subsequent performance tests to 26 calendar months following the date the previous performance test was conducted. If the results of any subsequent performance test exceed 75 percent of the NO_X emissions standard for the stationary combustion turbine, you must resume 14-calendar-month performance testing.

(3) An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days or 10 operating days, whichever is longer, after the next operating day. The Administrator or delegated authority must be notified of recommencement of operation consistent with § 60.4375a(d).

(4) If you own or operate an affected facility that has operated 168 operating hours or less, either in total or using a particular fuel, since the date on which the previous performance test was conducted, you may request that the otherwise required performance test be postponed until the affected facility has operated more than 168 operating hours, either in total or using a particular fuel, since the date on which the previous performance test was conducted. A request for an extension under this paragraph (b)(4) must be addressed to the relevant air division or office director of the appropriate Regional Office of the U.S. EPA as identified in § 60.4(a) for his or her approval at least 30 calendar days prior to the date on which the performance test is required to be conducted. If a postponement is approved, a performance test must be conducted within 45 calendar days after the day that the facility reaches 168 hours of operation since the date on which the previous performance test was conducted. When the facility has operated more than 168 operating hours since the date on which the previous performance test was conducted, the Administrator or delegated authority must be notified consistent with § 60.4375a(e).

(5) For a facility at which a group consisting of no more than five similar stationary combustion turbines (*i.e.,* same manufacturer and model number) is operated, you may request the use of a custom testing schedule by submitting a written request to the Administrator or delegated authority. The minimum requirements of the custom schedule include the conditions specified in paragraphs (b)(5)(i) through (v) of this section.

(i) Emissions from the most recent performance test for each individual affected facility are 75 percent or less of the applicable standard;

(ii) Each stationary combustion turbine uses the same emissions control technology;

(iii) Each stationary combustion turbine is operated in a similar manner;

(iv) Each stationary combustion turbine and its emissions control equipment are maintained according to the manufacturer's recommended maintenance procedures; and

(v) A performance test is conducted on each affected facility at least once every 5 calendar years.

(6) A stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a that exchanges the combustion turbine engine for an overhauled combustion turbine engine as part of an exchange program, must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. (as applicable).

(c) Except as provided for in paragraph (c)(1) or (2) of this section, for each stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_X emissions according to the provisions in § 60.4345a. If your stationary combustion turbine is equipped with a NO_X CEMS, those measurements must be used to determine excess emissions.

(1) If your stationary combustion turbine uses water or steam injection but not post-combustion controls to meet the applicable NO_X emissions standard in § 60.4320a, you may elect to demonstrate continuous compliance using the pounds per million British thermal units (lb/MMBtu) or parts per million (ppm) input-based standard according to the provisions in § 60.4335a.

(2) If your stationary combustion turbine does not use water injection, steam injection, or post-combustion controls to meet the applicable NO_X emissions standard in § 60.4320a, you may elect to demonstrate continuous compliance with an input-based standard according to the provisions in § 60.4340a.

(d) An owner or operator of a stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330a must demonstrate compliance using one of the methods specified in paragraphs (d)(1) through (4) of this section.

(1) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was conducted. An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day;

(2) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, conduct subsequent fuel sulfur analyses using the applicable methods specified in § 60.4360a and at the frequency specified in § 60.4370a;

(3) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370a; or

(4) Conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4415a. Thereafter, continue to monitor SO_2 emissions using a CEMS according to the requirements specified in § 60.4374a.

(e) If you elect to comply with an input-based standard (lb/MMBtu or ppm) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures specified in paragraph (e)(1) or (2) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the fuel flow to the combustion turbine engine and any associated duct burners.

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit and the total fuel flow to each combustion turbine engine and any associated duct burners. The applicable emissions standard for the affected facility is equal to the prorated (by heat input) emissions standards of each of the individual combustion turbine engines that are exhausted through the single heat recovery steam generating unit.

(f) If you elect to comply with an output-based standard (lb/MWh) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures in paragraph (f)(1), (2), or (3) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the total electrical, mechanical energy, and useful thermal output of the stationary combustion turbine (as applicable).

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit, and the total electrical, mechanical energy, and useful thermal output of the heat recovery steam generating unit and each combustion turbine engine (as applicable). The applicable emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engines.

(3) For a configuration where your combustion turbine engines are exhausted through two or more heat recovery steam generating units which serve a common steam turbine or steam header, you must measure both the emissions at the exhaust stack for each heat recovery steam generating unit and the total electrical or mechanical energy output of each combustion turbine engine (as applicable). To determine the net or gross energy output of the steam produced by the heat recovery steam generating unit, you must develop a custom method and provide information, satisfactory to the Administrator or delegated authority, apportioning the net or gross energy output of the steam produced by the heat recovery steam generating units to each of the affected stationary combustion turbines.

(g) If you elect to comply with the mass-based standard, you must demonstrate continuous compliance using either a CEMS for measuring NO_X emissions according to the provisions in § 60.4345a or using the methodology in appendix E to part 75 of this chapter.

MONITORING

§ 60.4335a How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I use water or steam injection?

If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333a(c)(1), you must install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the water or steam to fuel ratio fired in the combustion turbine engine consistent with the requirements in § 60.4342a. Water or steam only needs to be injected when a fuel is being combusted that requires water or steam injection for compliance with the applicable NO_X emissions standard.

§ 60.4340a How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I do not use water or steam injection?

(a) If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333a(c)(2), you must demonstrate compliance with the NO_X emissions standard using one of the methods specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct performance tests according to requirements in § 60.4400a;

(2) Monitor the NO_X emissions rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19 of this chapter; or

(3) Install, calibrate, maintain, and operate an operating parameter continuous monitoring system according to the requirements specified in paragraph (b) of this section and consistent with the requirements specified in § 60.4342a.

(b) If you opt to demonstrate compliance according to the procedures described in paragraph (a)(3) of this section, continuous operating parameter monitoring must be performed using the methods specified in paragraphs (b)(1) through (4) of this section as applicable to the stationary combustion turbine.

(1) Selection of the operating parameters used to comply with this paragraph (b) must be identified in the performance test report. The selection of operating parameters is subject to the review and approval of the Administrator or delegated authority.

(2) For a lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode during periods when low-NO_X operation is required to comply with the applicable emission NO_X standard.

(3) For a stationary combustion turbine other than a lean premix stationary combustion turbine, you must define parameters indicative of the unit's NO_X formation characteristics and monitor these parameters continuously.

(4) You must perform the parametric monitoring described in section 2.3 in appendix E to part 75 of this chapter or in § 75.19(c)(1)(iv)(H) of this chapter.

§ 60.4342a How do I monitor NO_X control operating parameters?

(a) If you monitor steam or water to fuel ratio according to § 60.4335a or other parameters according to § 60.4340a, the applicable parameters must be continuously monitored and recorded during the performance test, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations, and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must include the information specified in paragraphs (a)(1) through (6) of this section:

(1) Identification of the parameters to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls;

(2) Selected parameter ranges (or designated conditions) indicative of proper operation of the stationary combustion turbine NO_X emission controls, or describe the process by which such range (or designated condition) will be established;

(3) Explanation of the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable);

(4) Description of quality assurance and control practices used to ensure the continuing validity of the data;

(5) Description of the frequency of monitoring and the data collection procedures which you will use (*e.g.,* you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred); and

(6) Justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges.

(b) The water or steam to fuel ratio and parameter continuous monitoring system ranges must be confirmed or reestablished at least once every 60 calendar months following the previous calibration and each time the combustion turbine engine is replaced with an overhauled turbine engine as part of an exchange program. An affected facility that has not operated for 60 calendar days prior to the due date of a recalibration or has had the combustion turbine replaced with an overhauled turbine engine as part of an exchange program is not required to perform the subsequent recalibration until 45 calendar days after the next operating day.

§ 60.4345a How do I demonstrate compliance with my NO_X emissions standard using a NO_X CEMS?

(a) Each CEMS measuring NO_X emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of this section.

(1) You must install, certify, maintain, and operate a NO_X monitor to determine the hourly average NO_X emissions in the units of the standard with which you are complying.

(2) If you elect to comply with an input-based or mass-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

(3) If you elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate both a watt meter (or meters) to continuously measure the gross electrical output from the affected facility and either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor. If you have a CHP combustion turbine and elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate meters to continuously determine the total useful recovered thermal energy. For steam this includes flow rate, temperature, and pressure. If you have a direct mechanical drive application and elect to comply with the output-based emissions standard you must submit a plan to the Administrator or delegated authority for approval of how energy output will be determined.

(4) If you elect to comply with the part-load NO_X emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility.

(5) If you elect to comply with the temperature dependent NO_X emissions standard, you must install, calibrate, maintain, and operate a thermometer to continuously monitor the ambient temperature.

(6) If you combust natural gas with fuels other than natural gas and elect to comply with the fuels other than natural gas NO_X emissions standard, you must install, calibrate, maintain, and operate a device to continuously monitor when a fuel other than natural gas fuel is combusted in the combustion turbine engine.

(b) Each NO_X CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_X emissions rate. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 with approval from the Administrator or delegated authority, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis.

(c) During each full operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two data points (one in each of two quadrants) are required for each monitor.

(d) Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart.

(e) Each watt meter, steam flow meter, and each pressure or temperature measurement device must be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(f) You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of § 60.13(d), (e), and (h). For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of this paragraph (f) by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in § 60.13(d)(1).

(g) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.

§ 60.4350a How do I use the NO_X CEMS data to determine excess emissions?

(a) If you demonstrate continuous compliance using a CEMS for measuring NO_X emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating-hours, 30-operating-days, or 12-calendar-month), during which the average NO_X emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO_X emissions standard specified in § 60.4320a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) The NO_X CEMS data for each operating hour as measured according to the requirements in § 60.4345a must be used to determine the hourly average NO_X emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO_X, diluent, flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO_X emissions. All data points that are not collected during out-of-control periods must be used to determine the hourly average NO_X emissions.

(c) For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO_X emissions in units of lb/MMBtu or lbs, as applicable, using the appropriate equation from EPA Method 19 in appendix A-7 to this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(d) Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75. For units complying with the 12-calendar-month mass-based standard, emissions for hours of missing data shall be estimated by using the average emissions rate of non-out-of-control hours within ±10 percent of the hour of missing data within the 12-calendar-month period. If non-out-of-control data is not available, the maximum hourly emissions rate during the 12-calendar-month period shall be used.

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value.

(f) Calculate the hourly average NO_X emissions rate, in units of the emissions standard under § 60.4320a, using lb/MMBtu or ppm for units complying with the input-based standard, using lbs for units complying with the mass-based standard, or lb/MWh or kg/MWh for units complying with the output-based standard:

(1) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine engine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 1 and 2 to this paragraph (f)(1):

Equation 1 to Paragraph (f)(1)

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \text{ (Eq. 1)}$$

Where:

P = Gross or net energy output of the stationary combustion turbine system in MWh;

$(Pe)_t$ = Electrical or mechanical energy output of the combustion turbine engine in MWh;

$(Pe)_c$ = Electrical or mechanical energy output (if any) of the steam turbine in MWh;

Pe_A = Electric energy used for any auxiliary loads in MWh (only applicable to owners/operators electing to demonstrate compliance on a net output basis);

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine; and

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

Equation 2 to Paragraph (f)(1)

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \ Btu/MWh} \text{ (Eq. 2)}$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

Q_m = Measured steam flow in lb;

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb; and

3.413×10^6 = Conversion factor from Btu to MWh.

(2) For mechanical drive applications complying with the output-based standard, use equation 3 to this paragraph (f)(2):

Equation 3 to Paragraph (f)(2)

$$E = \frac{(NO_x)_m}{BL \times AL} \quad \text{(Eq. 3)}$$

Where:

E = NO_X emissions rate in lb/MWh;

$(NO_X)_m$ = NO_X emissions rate in lb/h;

BL = Manufacturer's base load rating of turbine, in MW; and

AL = Actual load as a percentage of the base load rating.

(g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NO_X emissions are determined on a 4-operating-hour averaging period basis using the NO_X CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NO_X emissions standard in table 1 to this subpart.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NO_X emissions as the heat input weighted average of the hourly average of NO_X emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NO_X emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average NO_X emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NO_X emissions rate and the applicable 4-operating-hour rolling average NO_X emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this paragraph (g)(2).

Equation 4 to Paragraph (g)(2)

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 4)}$$

Where:

E = 4-operating-hour rolling average NO_X emissions (lb/MMBtu or ng/J);

E_i = Hourly average NO_X emissions rate or emissions standard for operating hour “i” (lb/MMBtu or ng/J); and

Q_i = Total heat input to stationary combustion turbine for operating hour “i” (MMBtu or J as appropriate).

(h)

(1) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the NO_X emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control NO_X emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. If you elect to comply with the applicable output-based emissions rate standard, calculate the measured emissions rate using equation 5 to this paragraph (h)(1) and calculate the applicable emissions standard using equation 6 to this paragraph (h)(1). If you elect to comply with the applicable output-based emissions rate standard and determine the heat input on an hourly basis, calculate the 30-operating-day rolling average NO_X emissions rate using equation 5, and determine the applicable 30-operating-day rolling average NO_X emissions standard, calculated using values in table 1 to this subpart, using equation 6. Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard.

Equation 5 to Paragraph (h)(1)

$$E = \frac{\sum_{i=1}^{n} (E_i \times Q_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 5)}$$

Where:

E = 30-operating-day average NO_X measured emissions rate combustion turbines (lb/MWh or ng/J);

E_i = Hourly average NO_X emissions rate or emissions standard for non-out-of-control operating hour “i” (lb/MMBtu or ng/J);

Q_i = Total heat input to stationary combustion turbine for non-out-of-control operating hour “i” (MMBtu or J as appropriate);

P_i = Total gross or net energy output from stationary combustion turbine for non-out-of-control operating hour “i” (MWh or J); and

n = Total number of operating non-out-of-control hours in the 30-operating-day period.

Equation 6 to Paragraph (h)(1)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{non-NG} \times \frac{H_{non-NG}}{H_T} \quad (Eq. 6)$$

E = 30-operating-day rolling NO_X emissions standard (lb/MWh or kg/MWh);

E_{NG} = 30-operating-day emissions standard for natural gas-fired combustion turbines (lb/MWh or kg/MWh);

E_{non-NG} = 30-operating-day emissions standard for non-natural gas-fired combustion turbines (lb/MWh or kg/MWh);

H_{NG} = Hours of operation combusting natural gas during the 30-operating-day period;

H_{non-NG} = Hours of operation combusting non-natural gas fuels during the 30-operating-day period; and

H_T = Total hours of operation during the 30-operating-day period.

(2) If you elect to comply with the applicable output-based emissions rate standard and elect to not determine the heat input on an hourly basis, the applicable 30-operating-day emissions rolling NO_X standard is the most stringent standard applicable to the combustion turbine. The 30-operating-day rolling NO_X emissions rate is determined as the sum of the hourly emissions divided by the sum of the gross or net output over the 30-operating-day period.

(i) For each combustion turbine demonstrating compliance on a mass-based standard, you must determine excess NO_X emissions on both a rolling 4-operating-hour and rolling 12-calendar-month basis using the NO_X CEMS data and procedures specified in paragraphs (i)(1) through (4) of this section as applicable to the NO_X emissions standard in table 2 to this subpart. In addition, during system emergencies each combustion turbine must determine excess NO_X emissions using the procedures specified in paragraph (i)(5) of this section.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling NO_X emissions as the sum of the hourly NO_X emissions for a given operating hour and the 3 operating hours preceding that operating hour. Calculate a 4-operating-hour NO_X emissions rate for any 4-operating-hour period

when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling NO_X emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) Calculate the applicable 4-operating-hour rolling NO_X emissions standard, calculated using hourly values in table 2 to this subpart, using equation 7 to this paragraph (i)(2).

Equation 7 to Paragraph (i)(2)

$$E = \sum_{i=1}^{4} (E_i) \quad \text{(Eq. 7)}$$

Where:

E = 4-operating-hour rolling NO_X emissions (kg or lbs); and

E_i = Hourly NO_X emissions rate or emissions standard for operating hour “i” (kg or lbs).

(3) For each 12-calendar-month period, compute the 12-calendar-month rolling NO_X emissions as the sum of the hourly NO_X emissions for a given month and the 11 calendar months preceding the calendar month. Emissions during system emergencies are not included when calculating the 12-calendar-month emissions rate.

(4) Calculate the applicable 12-calendar-month rolling NO_X emissions standard, calculated using hourly values in table 2 to this subpart, using equation 8 to this paragraph (i)(4). Heat input during system emergencies is not included when calculating the 12-calendar-month emissions standard.

Equation 8 to Paragraph (i)(4)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{Non-NG} \times \frac{H_{non-NG}}{H_T} \quad \text{(Eq. 8)}$$

Where:

E = 12-calendar-month rolling NO_X emissions (tonnes or tons);

E_{NG} = 12-calendar-month emissions standard for natural gas-fired combustion turbines (tonnes or tons);

$E_{non\text{-}NG}$ = 12-calendar-month emissions standard for non-natural gas-fired combustion turbines (tonnes or tons);

H_{NG} = Hours of operation combusting natural gas during the 12-calendar-month period;

$H_{non\text{-}NG}$ = Hours of operation combusting non-natural gas fuels during the 12-calendar-month period; and

H_T = Total hours of operation during the 12-calendar-month period.

(5) During system emergencies during which the owner or operator elects to not include emissions or heat input in the 12-calendar month calculations, the applicable average natural gas-fired emissions standard is 0.83 lb NO_X/MW-rated output (1.8 lb NO_X/MW-rated output when firing non-natural gas) or the current emissions rate necessary to comply with the 12-calendar month natural gas-fired emissions standard of 0.48 tons NO_X/MW-rated output (0.81 tons NO_X/MW-rated output when firing non-natural gas) whichever is more stringent. For example, if a combustion turbine operated for 4,000 hours during the current 12-calendar month period the applicable average natural gas-fired emissions standard during the system emergency would be 0.24 lb NO_X/MW-rated output and the applicable average non-natural gas-fired emissions standard during the system emergency would be 0.41 lb NO_X/MW-rated output.

§ 60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333a(d)(2), the fuel analyses may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency as determined by the Administrator or delegated authority using the sampling frequency specified in § 60.4370a.

(b) Representative fuel analysis samples may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287-97 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177-95 (Reapproved 2000) (incorporated by reference, see § 60.17) for liquid fuels. For reference purposes when manually collecting gaseous samples, see Gas Processors Association Standard 2166-17 (incorporated by reference, see § 60.17). For reference purposes when manually collecting liquid samples, see either Gas Processors Association Standard 2174-14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057-95 (Reapproved 2000) (both of which are incorporated by reference, see § 60.17).

(c) Each collected fuel analysis sample must be analyzed for the total sulfur content of the fuel and heating value using the methods specified in paragraph (c)(1) or (2) of this section, as applicable to the fuel type.

(1) For the sulfur content of liquid fuels, ASTM D129-00 (Reapproved 2005), or alternatively D1266-98 (Reapproved 2003), D1552-03, D2622-05, D4294-03, D5453-05, D5623-24, or D7039-24 (all of which are incorporated by reference, see § 60.17). For the heating value of liquid fuels, ASTM D240-19 or D4809-18 (both of which are incorporated by reference, see § 60.17); or

(2) For the sulfur content of gaseous fuels, ASTM D1072-90 (Reapproved 1999), or alternatively D3246-05, D4468-85 (Reapproved 2000), D6667-04, or D5504-20 (all of which are incorporated by reference, see § 60.17). If the total sulfur content of the gaseous fuel during the most recent compliance demonstration was less than half the applicable standard, ASTM D4084-05, D4810-88 (Reapproved 1999), D5504-20, or D6228-98 (Reapproved 2003), or Gas Processors Association Standard 2140-17 or 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used. For the heating value of gaseous fuels, ASTM D1826-94 (Reapproved 2003), or alternatively D3588-98 (Reapproved 2003), D4891-89 (Reapproved 2006), or Gas Processors Association Standard 2172-09 (all of which are incorporated by reference, see § 60.17).

§ 60.4370a How frequently must I determine the fuel sulfur content?

(a) If you are complying with requirements in § 60.4360a, the total sulfur content of all fuels combusted in each stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330a must be determined according to the schedule specified in paragraph (a)(1) or (2) of this section, as applicable to the fuel type, unless you determine a custom schedule for the stationary combustion turbine according to paragraph (b) of this section.

(1) Use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 in appendix D to part 75 of this chapter (*i.e.,* flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank or sampling each delivery prior to combining it with liquid fuel already in the intended storage tank).

(2) If the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per operating day.

(b) As an alternative to the requirements of paragraph (a) of this section, you may implement custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply using the procedures provided in either paragraph (b)(1) or (2) of this section. Either you or the fuel vendor may perform the sampling. As an alternative to using one of these procedures, you may use a custom schedule that has been substantiated with data and approved by the Administrator or delegated authority as a change in monitoring prior to being used to comply with the applicable standard in § 60.4330a.

(1) You may determine and implement a custom sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) Obtain daily total sulfur content measurements for 30 consecutive operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content must be as specified in paragraph (b)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals provided the fuel source or supplier does not change. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable standard, follow the procedures in paragraph (b)(1)(iii) of this section. If any measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable standard, but none exceeds the applicable standard, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable standard, immediately begin daily monitoring according to paragraph (b)(1)(i) of this section. Daily monitoring must continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable standard, are obtained. At that point, the applicable procedures of paragraph (b)(1)(ii) or (iii) of this section must be followed.

(2) You may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 in appendix D to part 75 of this chapter to determine and implement a sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) If the maximum fuel sulfur content obtained from any of the 720 hourly samples does not exceed half the applicable standard, then the minimum required sampling frequency must be one sample at 12-month intervals.

(ii) If any sample result exceeds half the applicable standard, but none exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iii) of this section.

(iii) If the sulfur content of any of the 720 hourly samples exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iv) of this section.

§ 60.4372a How can I demonstrate compliance with my SO_2 emissions standard using records of the fuel sulfur content?

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333a(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of this section, as applicable to your stationary combustion turbine.

(b) If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330a(a), then the fuel combusted must have a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less.

(c) If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330a(b), then the total sulfur content of the gaseous fuel combusted must be 650 (mg/scm) (28 gr/100 scf).

(d) If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330a(c) or (d), the total sulfur content of the fuel combusted must be:

(1) For natural gas, 140 gr/100 scf or less.

(2) For fuel oil, 0.40 weight percent (4,000 ppmw) or less.

(3) For other fuels, potential SO_2 emissions of 180 ng/J (0.42 lb/MMBtu) heat input or less.

(e) Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of this chapter documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas. Your stationary combustion turbine may not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of:

(1) 110 ng SO_2/J (0.90 lb SO_2/MWh) gross energy output or 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input; or

(2) 780 ng SO_2/J (6.2 lb SO_2/MWh) gross energy output or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input if your combustion turbine is in a noncontinental area.

§ 60.4374a How do I demonstrate compliance with my SO_2 emissions standard and determine excess emissions using a SO_2 CEMS?

(a) If you demonstrate continuous compliance using a CEMS for measuring SO_2 emissions, excess emissions are defined as the applicable averaging period, either 4-operating-hour or 30-operating-day, during which the average SO_2 emissions from your stationary combustion turbine measured by the CEMS exceeds the applicable SO_2 emissions standard specified in § 60.4330a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) You must install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of your stationary combustion turbine, and record the output of the system.

(c) The 1-hour average SO_2 emissions rate measured by a CEMS must be expressed in ng/J or lb/MMBtu heat input and must be used to calculate the average emissions rate under § 60.4330a.

(d) You must use the procedures for installation, evaluation, and operation of the CEMS as specified in § 60.13 and paragraphs (d)(1) through (3) of this section.

(1) Each CEMS must be operated according to the applicable procedures under Performance Specifications 1, 2, and 3 in appendix B to this part;

(2) Quarterly accuracy determinations and daily calibration drift tests must be performed according to Procedure 1 in appendix F to this part; and

(3) The span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the stationary combustion turbine if no SO_2 control device is used) must be 125 percent of either the highest applicable standard or highest potential SO_2 emissions rate of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(e) If you have installed and certified a SO_2 CEMS that meets the requirements of part 75 of this chapter, the Administrator or delegated authority can approve that only quality assured data from the CEMS must be used to identify excess emissions under this subpart. You must report periods where the missing data substitution procedures in subpart D of part 75 are applied as monitoring system downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(f) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(g) Calculate the hourly average SO_2 emissions rate, in units of the emissions standard under § 60.4330a, using lb/MMBtu for units complying with the input-based standard or using equation 1 to paragraph (g)(1) of this section for units complying with the output-based standard:

(1) For simple cycle operation:

Equation 1 to Paragraph (g)(1)

$$E = \frac{(SO_2)_h \times Q}{P} \quad \text{(Eq. 1)}$$

Where:

E = Hourly SO_2 emissions rate, in lb/MWh;

$(SO_2)_h$ = Average hourly SO_2 emissions rate, in lb/MMBtu;

Q = Hourly heat input rate to the stationary combustion turbine, in MMBtu, measured using the fuel flow meter(s), *e.g.,* calculated using Equation D-15a in appendix D to part 75 of this chapter, an O_2 or CO_2 CEMS and a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter; and

P = Gross or net energy output of the stationary combustion turbine in MWh.

(2) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the stationary combustion turbine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 2 and 3 to this paragraph (g)(2); and any auxiliary load.

Equation 2 to Paragraph (g)(2)

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \quad \text{(Eq. 2)}$$

Where:

P = Gross energy output of the stationary combustion turbine system in MWh;

$(Pe)_t$ = Electrical or mechanical energy output of the stationary combustion turbine in MWh;

$(Pe)_c$ = Electrical or mechanical energy output (if any) of the steam turbine in MWh;

Pe_A = Electric energy used for any auxiliary loads in MWh;

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine; and

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

Equation 3 to Paragraph (g)(2)

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \ Btu/MWh} \quad \text{(Eq. 3)}$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh;

Q_m = Measured steam flow rate in lb;

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb; and

3.413×10^6 = Conversion factor from Btu to MWh.

(3) For mechanical drive applications complying with the output-based standard, use equation 4 to this paragraph (g)(3):

Equation 4 to Paragraph (g)(3)

$$E = \frac{(SO_2)_m}{BL \times AL} \quad \text{(Eq. 4)}$$

Where:

E = SO_2 emissions rate in lb/MWh;

$(SO_2)_m$ = SO_2 emissions rate in lb/h;

BL = Manufacturer's base load rating of turbine, in MW; and

AL = Actual load as a percentage of the base load rating.

(h) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess SO_2 emissions are determined on a 4-operating-hour averaging period basis using the SO_2 CEMS data and procedures specified in paragraphs (i)(1) and (2) of this section and as applicable to the SO_2 emission standard.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling average SO_2 emissions as the heat input weighted average of the hourly average of SO_2 emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (i)(2) of this section. Calculate a 4-operating-hour rolling average SO_2 emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average SO_2 emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average SO_2 emissions rate and the applicable 4-operating-hour rolling average SO_2 emission standard using equation 5 to this paragraph (h)(2).

Equation 5 to Paragraph (h)(2)

$$E = \frac{\sum_{i=1}^{4}(E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 5)}$$

Where:

E = 4-operating-hour rolling average SO_2 emissions (lb/MMBtu or ng/J);

E_i = Hourly average SO_2 emissions rate or emissions standard for operating hour “i” (lb/MMBtu or ng/J); and

Q_i = Total heat input to stationary combustion turbine for operating hour “i” (MMBtu or J as appropriate).

(i) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the SO_2 emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each operating day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control SO_2 emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. Calculate both the 30-operating-day rolling average SO_2 emissions rate and the applicable 30-operating-day rolling average SO_2 emissions standard using equation 6 to this paragraph (i).

Equation 6 to Paragraph (i)

$$E = \frac{\sum_{i=1}^{n}(E_i \times Q_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 6)}$$

Where:

E = 30-operating-day average SO_2 measured emissions rate (lb/MWh or ng/J);

E_i = Hourly average SO_2 measured emissions rate for non-out-of-control operating hour “i” (lb/MMBtu or ng/J);

Q_i = Total heat input to stationary combustion turbine for non-out-of-control operating hour "i" (MMBtu or J as appropriate);

P_i = Total gross energy output from stationary combustion turbine for non-out-of-control operating hour "i" (MWh or J); and

n = Total number of non-out-of-control operating hours in the 30-operating-day period.

(j) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.

RECORDKEEPING AND REPORTING

§ 60.4375a What reports must I submit?

(a) An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

(b) The notification requirements of § 60.8 apply to the initial and subsequent performance tests.

(c) An owner or operator of an affected facility complying with § 60.4333a(b)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation.

(d) An owner or operator of an affected facility complying with § 60.4333a(b)(4) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted.

(e) Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov,* and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqps_cbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

§ 60.4380a How are NO_X excess emissions and monitor downtime reported?

(a) For a stationary combustion turbine that uses water or steam to fuel ratio monitoring and is subject to the reporting requirements under § 60.4375a(a), periods of excess emissions and monitor downtime must be reported as specified in paragraphs (a)(1) through (3) of this section.

(1) An excess emission that must be reported is any operating hour for which the 4-operating-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, is less than the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320a, as established during the most recent performance test. Any operating hour during which no water or steam is injected into the turbine when the specific conditions require water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime that must be reported is any operating hour in which water or steam is injected into the turbine, but the parametric data needed to determine the steam or water to fuel ratio are unavailable or out-of-control.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the stationary combustion turbine load during each excess emission.

(b) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour average NO_X emissions rate, 30-operating-day rolling average NO_X emissions rate, 4-hour mass-based emissions rate, or the 12-calendar-month mass-based emissions rate exceeds the applicable emissions standard in § 60.4320a as determined in § 60.4350a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: NO_X concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

(c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO_X emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) Excess emissions that must be reported are each 4-operating-hour rolling average in which any monitored parameter (as averaged over the 4-operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data that are used to calculate the emission rate, as applicable, used to determine compliance, are either not recorded or are out-of-control.

§ 60.4385a How are SO_2 excess emissions and monitor downtime reported?

(a) If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitor downtime are defined as follows:

(1) For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard.

(2) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (*i.e.,* daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.

(3) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(b) If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard.

(c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour or 30-operating-day rolling average SO_2 emissions rate exceeds the applicable emissions standard in § 60.4330a as determined in § 60.4374a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: SO_2 concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

§ 60.4390a What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7.

(b) An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO_X standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable.

(c) An owner or operator of a stationary combustion turbine that uses the tuning NO_X standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance.

(d) An owner or operator of a stationary combustion turbine that demonstrates compliance using the output-based standard must maintain concurrent records of the total gross or net energy output and emissions data.

(e) An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters.

(f) An owner or operator of a stationary combustion turbine complying with the fuel-based SO_2 standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract.

§ 60.4395a When must I submit my reports?

Consistent with § 60.7(c), all reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period.

PERFORMANCE TESTS

§ 60.4400a How do I conduct performance tests to demonstrate compliance with my NO_X emissions standard if I do not have a NO_X CEMS?

(a) You must conduct the performance test according to the requirements in § 60.8 and paragraphs (b) through (d) of this section.

(b) You must use the methods in either paragraph (b)(1) or (2) of this section to measure the NO_X concentration for each test run.

(1) Measure the NO_X concentration using EPA Method 7E in appendix A-4 to this part, EPA Method 20 in appendix A-7 to this part, EPA Method 320 in appendix A to part 63 of this chapter, or ASTM D6348-12 (Reapproved 2020) (incorporated by reference, see § 60.17). For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then, use equation 1 to this paragraph (b)(1) to calculate the NO_X emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.194 \times 10^{-7} \times (NO_x)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:

E = NO_X emissions rate, in lb/MWh;

1.194×10^{-7} = Conversion constant, in lb/dscf-ppm;

$(NO_X)_c$ = Average NO_X concentration for the run, in ppm;

Q_{std} = Average stack gas volumetric flow rate, in dscf/h; and

P = Average gross or net electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350a.

(2) Measure the NO_X and diluent gas concentrations using either EPA Method 7E in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. In addition, when only natural gas is being combusted ASTM D6522-20 (incorporated by reference, see § 60.17) can be used instead of EPA Method 3A in appendix A-2 to this part or EPA Method 20 in appendix A-7 to this part to determine the oxygen content in the exhaust gas. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard measure the electrical, mechanical, and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the NO_X emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 in § 60.4350a(f) to calculate the NO_X emissions rate in lb/MWh.

(c) You must use the methods in either paragraph (c)(1) or (2) of this section to select the sampling traverse points for NO_X and (if applicable) diluent gas.

(1) You must select the sampling traverse points for NO_X and (if applicable) diluent gas according to EPA Method 20 in appendix A-7 to this part or EPA Method 1 in appendix A-1 to this part (non-particulate procedures) and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(2) As an alternative to paragraph (c)(1) of this section, you may select the sampling traverse points for NO_X and (if applicable) diluent gas according to requirements in paragraphs (c)(2)(i) and (ii) of this section.

(i) You perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) in appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, you use the following alternative sample point selection criteria for the performance test specified in paragraphs (c)(2)(ii)(A) through (C) of this section.

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For a stationary combustion turbine subject to a NO_X emissions standard greater than 15 ppm at 15 percent O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For a stationary combustion turbine subject to a NO_X emissions standard less than or equal to 15 ppm at 15 percent O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(d) The performance test must be done at any load condition within ±25 percent of 100 percent of the base load rating. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both natural gas and fuels other than natural gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle or CHP combustion turbine with supplemental heat (duct burner), you must measure the total NO_X emissions downstream of the duct burner. The duct burner must be in operation within ±25 percent of 100 percent of the base load rating of the duct burners or the highest achievable load if at least 75 percent of the base load rating of the duct burners cannot be achieved during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335a, then that monitoring system must be operated concurrently with each EPA Method 20 in appendix A-7 to this part or EPA Method 7E in appendix A-4 to this part run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320a NO_X emissions standard.

(4) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405a) as part of the initial performance test of the affected unit.

(5) The ambient temperature must be greater than 0 °F during the performance test. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

§ 60.4405a How do I conduct a performance test if I use a NO_X CEMS?

(a) If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of this section.

(b) The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section.

(1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±25 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

(2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.

(3) Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under § 60.4320a and to provide the required reference method data for the RATA of the CEMS described under § 60.4342a.

(4) Compliance with the applicable emissions standard in § 60.4320a is achieved if the sum of the NO_X emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu, ppm, lb/MWh, or kgs, does not exceed the emissions standard.

§ 60.4415a How do I conduct performance tests to demonstrate compliance with my SO_2 emissions standard?

(a) If you are an owner or operator of an affected facility complying with the fuel-based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8.

(b) If you are an owner or operator of an affected facility complying with the SO_2 emissions standard must conduct the performance test by measuring the SO_2 emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section.

(1) Measure the SO_2 concentration using EPA Method 6, 6C, or 8 in appendix A-4 to this part or EPA Method 20 in appendix A-7 to this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then use equation 1 to this paragraph (b)(1) to calculate the SO_2 emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:

E = SO_2 emissions rate, in lb/MWh;

1.664×10^{-7} = Conversion constant, in lb/dscf-ppm;

$(SO_2)_c$ = Average SO_2 concentration for the run, in ppm;

Q_{std} = Average stack gas volumetric flow rate, in dscf/h; and

P = Average gross electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350a(f)(2).

(2) Measure the SO_2 and diluent gas concentrations, using either EPA Method 6, 6C, or 8 in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the SO_2 emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2, 3, and 4 in § 60.4374a to calculate the SO_2 emissions rate in lb/MWh.

OTHER REQUIREMENTS AND INFORMATION

§ 60.4416a What parts of the general provisions apply to my affected EGU?

(a) Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 2 to this subpart, do not apply to your affected combustion turbine.

(b) Small, medium, and low utilization large combustion turbines that are subject to this subpart and are not a “major source” or located at a “major source” (as that term is defined at 42 U.S.C. 7661(2)) are exempt from the requirements of 42 U.S.C. 7661a(a).

§ 60.4417a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your State, local, or Tribal agency. If the Administrator has delegated authority to your State, local, or Tribal agency, then that agency, (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (6) of this section and does not transfer them to the State, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emissions standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

§ 60.4420a What definitions apply to this subpart?

As used in this subpart, all terms not defined in this section will have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a stationary combustion turbine during a calendar year and the potential heat input to the stationary combustion turbine had it been operated for 8,760 hours during a calendar year at the base load rating. Heat input during a system emergency as defined in § 60.4420a is excluded when determining the annual capacity factor. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel. The base load rating does not include any potential heat input to an HRSG.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and $CO_{2.}$

Byproduct means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, pulp and paper mills, or other industrial facilities (except natural gas and fuel oil).

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine.

Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine engine means the air compressor, combustor, and turbine sections of a stationary combustion turbine.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 or 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17), kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17), biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17), or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

District energy system means a central plant producing hot water, steam, and/or chilled water, which then flows through a network of insulated pipes to provide hot water, space heating, and/or air conditioning for commercial, institutional, or residential buildings.

Dry standard cubic foot (dscf) means the quantity of gas, free of uncombined water, that would occupy a volume of 1 cubic foot at 293 Kelvin (20 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire (*e.g.,* firefighting turbine) or flood, etc. Emergency combustion turbines may be operated for maintenance checks and readiness testing to retain their status as emergency combustion turbines, provided that the tests are recommended by Federal, State, or local government, agencies, or departments, voluntary consensus standards, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the combustion turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines. Emergency combustion turbines do not include combustion turbines used as peaking units at electric utilities or combustion turbines at industrial facilities that typically operate at low capacity factors.

Excess emissions means a specified averaging period over which either:

(1) The NO_X or SO_2 emissions rate are higher than the applicable emissions standard in § 60.4320a or § 60.4330a;

(2) The total sulfur content of the fuel being combusted in the affected facility or the SO_2 emissions exceeds the standard specified in § 60.4330a; or

(3) The recorded value of a particular monitored parameter, including the water or steam to fuel ratio, is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator or delegated authority, including the requirements of this part and part 61 of this chapter, requirements within any applicable State Implementation Plan, and any permit requirements established under § 52.21 or §§ CFR 51.18 and 51.24 of this chapter.

Firefighting combustion turbine means any stationary combustion turbine that is used solely to pump water for extinguishing fires.

Fuel oil means a fluid mixture of hydrocarbons that maintains a liquid state at ISO conditions. Additionally, fuel oil must meet the definition of either distillate oil (as defined in this subpart) or liquefied petroleum (LP) gas as defined in ASTM D1835-03a (incorporated by reference, see § 60.17).

Garrison facility means any permanent military installation.

Gross energy output means:

(1) For simple cycle and combined cycle combustion turbines, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s).

(2) For a CHP combustion turbine, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.*e.,* steam delivered to an industrial process).

(3) For a CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process).

(4) For a district energy CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on a 12-calendar-month basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process) divided by 0.95.

Heat recovery steam generating unit (HRSG) means a unit where the hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners. A heat recovery steam generating unit operating independent of the combustion turbine engine may operate burners using ambient air.

High-utilization source means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor greater than 45 percent.

Integrated gasification combined cycle electric utility steam generating unit (IGCC) means an electric utility steam generating unit that combusts solid-derived fuels in a combined cycle combustion turbine. No solid fuel is directly combusted in the unit during operation.

ISO conditions mean 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.325 kilopascals (14.69 psi, 1 atm) pressure.

Large combustion turbine means a stationary combustion turbine with a base load rating greater than 850 MMBtu/h of heat input.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Low-Btu gas means biogas or any gas with a heating value of less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

Low-utilization source means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor less than or equal to 45 percent.

Medium combustion turbine means a stationary combustion turbine with a base load rating greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input.

Natural gas means a fluid mixture of hydrocarbons, composed of at least 70 percent methane by volume, that has a gross calorific value between 35 and 41 MJ/scm (950 and 1,100 Btu/scf), and that maintains a gaseous state under ISO conditions. Unless processed to meet this definition of natural gas, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility plus 100 percent of the useful thermal output; or

(2) For CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output.

(3) For district energy CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output divided by 0.95.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore turbines.

Offshore turbine means a stationary combustion turbine located on a platform or facility in an ocean, territorial sea, the outer continental shelf, or the Great Lakes of North America and stationary combustion turbines located in a coastal management zone and elevated on a platform.

Operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, the operating hour is a full operating hour. If the unit combusts fuel for only part of the clock hour, the operating hour is a partial operating hour.

Out-of-control period means any period beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the hour corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

Small combustion turbine means a stationary combustion turbine with a base load rating less than or equal to 50 MMBtu/h of heat input.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard cubic foot (scf) means the quantity of gas that would occupy a volume of 1 cubic foot at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Standard cubic meter (scm) means the quantity of gas that would occupy a volume of 1 cubic meter at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Stationary combustion turbine means all equipment including, but not limited to, the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except post combustion emissions control equipment), heat recovery system (including heat recovery steam generators and duct burners); steam turbine; fuel compressor and/or pump, any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system; plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine (*e.g.,* onsite photovoltaics), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of "stationary combustion turbine," and not regulated under this part, if the turbine meets the definition of "nonroad engine" under title II of the Clean Air Act and applicable regulations and is certified to meet emissions standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 1, 2, or 3, which should follow NERC Reliability Standard EOP-011-2, its successor, or equivalent.

Temporary combustion turbine means a combustion turbine that is intended to and remains at a single stationary source (or group of stationary sources located within a contiguous area and under common control) for 24 consecutive months or less.

Turbine tuning means planned maintenance or parameter performance testing of a combustion turbine engine involving adjustment of the operating configuration to maintain proper combustion dynamics or testing machine operating performance. Turbine tuning is limited to 30 hours annually.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation or mechanical output at the affected facility to directly enhance the performance of the affected facility (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output) or to supply energy to a pollution control device at the affected facility (*e.g.,* steam provided to a carbon capture system would not be considered useful thermal output). Useful thermal output for affected facilities with no condensate return (or other thermal energy input to affected facilities) or where measuring the energy in the condensate (or other thermal energy input to the affected facilities) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions (*e.g.* liquid water). Affected facilities with meaningful energy in the condensate return (or other thermal energy input to the affected facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to this part or part 75 of this chapter as applicable. For CEMS maintained according to part 75, the initial certification requirements in § 75.20 and appendix A to part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 must be met. For fuel flow meters maintained according to part 75, the initial certification requirements in section 2.1.5 of appendix D to part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters). Any out-of-control data is not considered valid data.

Table 1 to Subpart KKKKa of Part 60—Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO_X emission standard [1]	Optional output-based NO_X standard [2]
New, firing natural gas with utilization rate >45 percent	>850 MMBtu/h	5 ppm at 15 percent O_2 or 7.9 ng/J (0.018 lb/MMBtu)	0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net).
New, firing natural gas with utilization rate ≤45 percent and with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net).
New, firing natural gas with utilization rate ≤45 percent and with design efficiency <38 percent	>850 MMBtu/h	9 ppm at 15 percent O_2 or 14 ng/J (0.033	0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*

[2] *Output-based standards are determined on a 30-operating-day average basis.*

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO_X emission standard [1]	Optional output-based NO_X standard [2]
		lb/ MMBtu)	net).
New, modified, or reconstructed, firing non-natural gas	>850 MMBtu/h	42 ppm at 15 percent O_2 or 70 ng/J (0.16 lb/ MMBtu)	0.45 kg/MWh-gross (1.0 lb/ MWh-gross) 0.46 kg/MWh-net (1.0 lb/ MWh-net).
Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency ≥38 percent	>850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/ MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net).
Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency <38 percent	>850 MMBtu/h	15 ppm at 15 percent O_2 or 24 ng/J (0.055 lb/ MMBtu)	0.28 kg/MWh-gross (0.62 lb/MWh-gross) 0.29 kg/MWh-net (0.30 lb/MWh-net).
New, firing natural gas, at utilization rate >45 percent	>50 MMBtu/h and ≤850 MMBtu/h	15 ppm at 15 percent O_2 or 24 ng/J (0.055 lb/ MMBtu)	0.20 kg/MWh-gross (0.43 lb/MWh-gross) 0.20 kg/MWh-net (0.44 lb/MWh-net).
New, firing natural gas, at utilization rate ≤45 percent	>50 MMBtu/h and ≤850 MMBtu/h	25 ppm at 15 percent O_2 or 40	0.54 kg/MWh-gross (1.2 lb/ MWh-gross) 0.56 kg/MWh-

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*

[2] *Output-based standards are determined on a 30-operating-day average basis.*

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO_X emission standard [1]	Optional output-based NO_X standard [2]
		ng/J (0.092 lb/MMBtu)	net (1.2 lb/MWh-net).
Modified or reconstructed, firing natural gas	>20 MMBtu/h and ≤850 MMBtu/h	42 ppm at 15 percent O_2 or 67 ng/J (0.15 lb/MMBtu)	0.91 kg/MWh-gross (2.0 lb/MWh-gross) 0.92 kg/MWh-net (2.0 lb/MWh-net).
New, firing non-natural gas	>50 MMBtu/h and ≤850 MMBtu/h	74 ppm at 15 percent O_2 or 120 ng/J (0.29 lb/MMBtu)	1.6 kg/MWh-gross (3.6 lb/MWh-gross) 1.6 kg/MWh-net (3.7 lb/MWh-net).
Modified or reconstructed, firing non-natural gas	>20 MMBtu/h and ≤850 MMBtu/h	96 ppm at 15 percent O_2 or 160 ng/J (0.37 lb/MMBtu)	2.1 kg/MWh-gross (4.7 lb/MWh-gross) 2.2 kg/MWh-net (4.8 lb/MWh-net).
New, firing natural gas	≤50 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.64 kg/MWh-gross (1.4 lb/MWh-gross) 0.65 kg/MWh-net (1.4 lb/MWh-net).
New, firing non-natural gas	≤50 MMBtu/h	96 ppm at 15 percent O_2 or	2.4 kg/MWh-gross (5.3 lb/MWh-gross) 2.5 kg/MWh-

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*

[2] *Output-based standards are determined on a 30-operating-day average basis.*

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO_X emission standard [1]	Optional output-based NO_X standard [2]
		160 ng/J (0.37 lb/ MMBtu)	net (5.4 lb/ MWh-net).
Modified or reconstructed, all fuels	≤20 MMBtu/h	150 ppm at 15 percent O_2 or 240 ng/J (0.55 lb/ MMBtu)	3.9 kg/MWh-gross (8.7 lb/ MWh-gross) 4.0 kg/MWh-net (8.9 lb/ MWh-net).
New, firing natural gas, either offshore turbines, turbines bypassing the heat recovery unit, and/or temporary turbines	>50 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/ MMBtu)	N/A.
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	≤300 MMBtu/h	150 ppm at 15 percent O_2 or 240 ng/ J) 0.55 lb/ MMBtu	N/A.
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	>300 MMBtu/h	96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/ MMBtu)	N/A.
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 86	N/A.

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*

[2] *Output-based standards are determined on a 30-operating-day average basis.*

Combustion turbine type	Combustion turbine base load rated heat input (HHV)	Input-based NO_X emission standard [1]	Optional output-based NO_X standard [2]
		ng/J) 0.20 lb/ MMBtu	

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*

[2] *Output-based standards are determined on a 30-operating-day average basis.*

Table 2 to Subpart KKKKa of Part 60—Alternative Mass-Based NO_X Emission Standards for Stationary Combustion Turbines

Combustion turbine type	4-Hour emissions rate (lb NO_X/MW-rated output)	12-Calendar-month emissions rate (ton NO_X/MW-rated output)
Natural Gas	0.38 kg NO_X/MW-rated output (0.83 lb NO_X/MW-rated output)	0.44 tonne NO_X/MW-rated output (0.48 ton NO_X/MW-rated output).
Non-Natural Gas	0.82 kg NO_X/MW-rated output (1.8 lb NO_X/MW-rated output)	0.74 tonne NO_X/MW-rated output (0.81 ton NO_X/MW-rated output).

Table 3 to Subpart KKKKa of Part 60—Applicability of Subpart A of This Part to This Subpart

General provisions citation	Subject of citation	Applies to subpart KKKKa	Explanation
§ 60.1	Applicability	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4420a.
§ 60.3	Units and Abbreviations	Yes	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of	Yes	

General provisions citation	Subject of citation	Applies to subpart KKKKa	Explanation
	construction or modification		
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	Yes	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)	Conducting performance tests	No	Overridden by § 60.4320a(d).
§ 60.8(d)-(f)	Conducting performance tests	Yes	
§ 60.9	Availability of Information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	
§ 60.12	Circumvention	Yes	
§ 60.13(a)-(h), (j)	Monitoring requirements	Yes	
§ 60.13(i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	No	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	Yes	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 of this chapter or to information reported through ECMPS.

APPENDIX G

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 60 —Standards of Performance for New Stationary Sources

Authority: 42 U.S.C. 7401 *et seq.*

Source: 36 FR 24877, Dec. 23, 1971, unless otherwise noted.

Subpart TTTTa Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Applicability

§ 60.5508a What is the purpose of this subpart?

§ 60.5509a Am I subject to this subpart?

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

§ 60.5520a What CO_2 emissions standard must I meet?

§ 60.5525a What are my general requirements for complying with this subpart?

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

§ 60.5555a What reports must I submit and when?

§ 60.5560a What records must I maintain?

§ 60.5565a In what form and how long must I keep my records?

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

§ 60.5575a Who implements and enforces this subpart?

§ 60.5580a What definitions apply to this subpart?

Table 1 to Subpart TTTTa of Part 60

CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

Table 2 to Subpart TTTTa of Part 60

CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023

Table 3 to Subpart TTTTa of Part 60

Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Source: 89 FR 40035, May 9, 2024, unless otherwise noted.

APPLICABILITY

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

EMISSION STANDARDS

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (e.g., non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2 \ emissions \ standard = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2 \ emissions \ standard = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

MONITORING AND COMPLIANCE DETERMINATION PROCEDURES

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of 40 CFR part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the "stack operating time" (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.,* operating hours for which:

(i) "Valid data" (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,] \text{ (Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.*, CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

NOTIFICATION, REPORTS, AND RECORDS

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.*, the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)

(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)

(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)

(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

OTHER REQUIREMENTS AND INFORMATION

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions) of this part.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388-99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as "cogeneration") means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22-2014, ASME PTC 46-1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions.

Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[NOTE: NUMERICAL VALUES OF 1,000 OR GREATER HAVE A MINIMUM OF 3 SIGNIFICANT FIGURES AND NUMERICAL VALUES OF LESS THAN 1,000 HAVE A MINIMUM OF 2 SIGNIFICANT FIGURES]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)-(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)-(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

APPENDIX H

Title 40 —Protection of Environment
Chapter I —Environmental Protection Agency
Subchapter C —Air Programs
Part 63 —National Emission Standards for Hazardous Air Pollutants for Source Categories

Authority: 42 U.S.C. 7401 *et seq.*

Source: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

§ 63.6585 Am I subject to this subpart?

§ 63.6590 What parts of my plant does this subpart cover?

§ 63.6595 When do I have to comply with this subpart?

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

§ 63.6615 When must I conduct subsequent performance tests?

§ 63.6620 What performance tests and other procedures must I use?

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

§ 63.6650 What reports must I submit and when?

§ 63.6655 What records must I keep?

§ 63.6660 In what form and how long must I keep my records?

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

§ 63.6670 Who implements and enforces this subpart?

§ 63.6675 What definitions apply to this subpart?

Table 1a to Subpart ZZZZ of Part 63

Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

Table 1b to Subpart ZZZZ of Part 63

Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

Table 2a to Subpart ZZZZ of Part 63

Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

Table 2b to Subpart ZZZZ of Part 63

Operating Limitations for New and Reconstructed 2SLB and CI

Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

Table 2c to Subpart ZZZZ of Part 63
Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

Table 2d to Subpart ZZZZ of Part 63
Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

Table 3 to Subpart ZZZZ of Part 63
Subsequent Performance Tests

Table 4 to Subpart ZZZZ of Part 63
Requirements for Performance Tests

Table 5 to Subpart ZZZZ of Part 63
Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

Table 6 to Subpart ZZZZ of Part 63
Continuous Compliance With Emission Limitations, and Other Requirements

Table 7 to Subpart ZZZZ of Part 63
Requirements for Reports

Table 8 to Subpart ZZZZ of Part 63
Applicability of General Provisions to Subpart ZZZZ

Appendix A to Subpart ZZZZ of Part 63
Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.*

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.*

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.*

(1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) ***Stationary RICE subject to Regulations under 40 CFR Part 60.*** An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.*

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) ***Area sources that become major sources.*** If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

EMISSION AND OPERATING LIMITATIONS

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than

June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013; 89 FR 70515, Aug. 30, 2024]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) [Reserved]

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013, as amended at 85 FR 78463, Dec. 4, 2020; 87 FR 48607, Aug. 10, 2022]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

TESTING AND INITIAL COMPLIANCE REQUIREMENTS

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)

(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq.\ 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

(j) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedure specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(5) Beginning on February 26, 2025, within 60 days after the date of completing each continuous emissions monitoring system (CEMS) performance evaluation (as defined in § 63.2) that includes a relative accuracy test audit (RATA), you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). The results of performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or alternate electronic file.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of table 2c to this subpart or in items 1 or 4 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of table 2c to this subpart or in items 5, 6, 7, 8, 10, 11, or 13 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

CONTINUOUS COMPLIANCE REQUIREMENTS

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

NOTIFICATIONS, REPORTS, AND RECORDS

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an initial notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in portable document format (PDF) consistent with § 63.9(k).

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an initial notification not later than July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008, and you are required to submit an initial notification, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) Before February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2). Beginning on February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including a summary of the performance test results, in PDF to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), before the close of business on the 60th day following the completion of the performance test following the procedure specified in § 63.9(k), except any Confidential Business Information (CBI) is to be submitted according to paragraphs (h)(2)(i) and (ii) of this section. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file, including information claimed to be CBI, to the EPA following the procedures in paragraphs (h)(2)(i) and (ii) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(2).

(i) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (h)(2) of this section, should include clear CBI markings and be flagged to the attention of the Reciprocating Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711, Attention Reciprocating Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013; 85 FR 73912, Nov. 19, 2020; 89 FR 70516, Aug. 30, 2024]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (8) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the starting and ending date and time, the duration (in hours), and a brief description for each malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(7) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

(8) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(9) An engine can be claimed as exempt from reporting coordinates (latitude/longitude) via CEDRI if:

(i) During the reporting period, the engine will be owned by, or operated by or for, an agency of the Federal Government responsible for national defense; and

(ii) The agency determines that disclosing the coordinates to the general public would be a threat to national security.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (8) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time (in hours) of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration (in hours), and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) A description of any changes in processes, or controls since the last reporting period.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (8) and (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The start and end date and time and the duration (in hours) that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The start and end date and time and the duration (in hours) that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration (in hours) of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration (in hours) of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration (in hours) of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) [Reserved]

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(13) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. Beginning on February 26, 2025, the semiannual and annual compliance report required in table 7 of this subpart must be submitted according to paragraph (i) of this section. Only those elements required under this subpart are required to be submitted according to paragraph (i) of this section.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration (in hours), and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) Before February 26, 2025, the annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13. Beginning on February 26, 2025, the annual report must be submitted according to paragraph (i) of this section.

(i) Beginning on February 26, 2025 for the annual report specified in § 63.6650(h) and February 26, 2025 or one year after the report becomes available in CEDRI, whichever is later for all other semiannual or annual reports, submit all semiannual and annual subsequent compliance reports using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k), except any CBI must be submitted according to the procedures in § 63.6645(h). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70517, Aug. 30, 2024]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) Records of the occurrence and duration (in hours) of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purpose specified in § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70518, Aug. 30, 2024]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

OTHER REQUIREMENTS AND INFORMATION

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

[69 FR 33506, June 15, 2004, as amended at 89 FR 70518, Aug. 30, 2024]

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013; 87 FR 48608, Aug. 10, 2022]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.*

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.*

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP	Comply with any operating limitations approved by the Administrator.

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.*

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.*

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.*

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.*

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.*

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
oxidation catalyst	water from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	Comply with any operating limitations approved by the Administrator.

[1] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.*

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE [1]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first [2]. b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary [3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first [2].	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary [3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	

[1] *If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.*

[2] *Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.*

[3] *Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.*

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Reduce CO emissions by 70 percent or more	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [2]	
	b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary [3]	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [2]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary [3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [2]	
	b. Inspect spark plugs every 4,320 hours of	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary [3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	less at 15 percent O_2	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[89 FR 70518, Aug. 30, 2024]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1] b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1] b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1] b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1]	
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

[1] *Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.*

[2] *If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.*

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	change, whichever comes first; [1]	
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	change, whichever comes first; [1] b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1] b. Inspect spark plugs every 2,160 hours of operation or	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first; [1] b. Inspect spark plugs every 1,440 hours of operation or	

[1] *Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.*

[2] *If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.*

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

[1] *Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.*

[2] *If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.*

[89 FR 70520, Aug. 30, 2024]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Select the sampling port location and the number/ location of traverse points at the inlet and outlet of the control device; and		(a) For CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005) [1 3] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.

[1] *You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).*

[2] *You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.*

[3] *Incorporated by reference, see § 63.14.*

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		iii. Measure the CO at the inlet and the outlet of the control device; and	(2) ASTM D6522-00 (Reapproved 2005) [1 2 3] (heated probe not necessary) or method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
		iv. Measure moisture content at the inlet and outlet of the control device as needed to determine CO and O_2 concentrations on a dry basis	(3) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 [1 3]	(d) Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	i. Select the sampling port location and the number/ location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, THC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of

[1] *You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).*

[2] *You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.*

[3] *Incorporated by reference, see § 63.14.*

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
				method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005) [1 3] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 [1 3]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance	(3) Method 320 or 323 of 40 CFR	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the

[1] *You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).*

[2] *You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.*

[3] *Incorporated by reference, see § 63.14.*

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	part 63, appendix A; or ASTM D6348-03,[1 3] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(4) (1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(e) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary	i. Select the sampling port location and the number/ location of traverse points		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse

[1] You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).

[2] You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[3] Incorporated by reference, see § 63.14.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
	RICE exhaust	at the exhaust of the stationary RICE; and		points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005) [1 3] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location as	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63,	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.

[1] *You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).*

[2] *You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.*

[3] *Incorporated by reference, see § 63.14.*

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		needed to determine formaldehyde or CO and O_2 concentrations on a dry basis; and	appendix A, or ASTM D6348-03 [1] [3]	
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[1] [3] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(4) Method 10 of 40 CFR part 60, appendix A-4, ASTM D6522-00 (2005),[1] [3] method 320	(e) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[1] You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).

[2] You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[3] Incorporated by reference, see § 63.14.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
			of 40 CFR part 63, appendix A, or ASTM D6348-03 [1] [3]	

[1] *You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).*

[2] *You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.*

[3] *Incorporated by reference, see § 63.14.*

[88 FR 18413, Mar. 29, 2023]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde	i. The average reduction of emissions of formaldehyde

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
	emissions and using NSCR	determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB	a. Limit the concentration of formaldehyde in the stationary	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
stationary RICE >500 HP located at a major source of HAP	RICE exhaust and using oxidation catalyst or NSCR	ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
that are operated more than 24 hours per calendar year		that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or	a. Reduce CO emissions or	i. Collecting the monitoring data

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
	RICE exhaust and using oxidation catalyst or NSCR	emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed	a. Limit the concentration	i. Conducting semiannual

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE		instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust,	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
	and not using oxidation catalyst	appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration	i. Conducting performance tests every 8,760 hours or 5 years,

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
	of CO in the stationary RICE exhaust, and using an oxidation catalyst	whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages;

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a] *After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.*

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) and (i) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b) and (i).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4)	i. Semiannually according to the requirements in § 63.6650(b) and (i).

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i).
4. Emergency stationary RICE that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. Annually according to the requirements in § 63.6650(h)(2)-(3) and (i).

[89 FR 70522, Aug. 30, 2024]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes	
§ 63.4	Prohibited activities and circumvention	Yes	
§ 63.5	Construction and reconstruction	Yes	
§ 63.6(a)	Applicability	Yes	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes	
§ 63.6(b)(5)	Notification	Yes	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No	
§ 63.6(f)(1)	Applicability of standards	No	
§ 63.6(f)(2)	Methods for determining compliance	Yes	
§ 63.6(f)(3)	Finding of compliance	Yes	
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.6(j)	Presidential compliance exemption	Yes	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes	
§ 63.7(e)(1)	Conditions for conducting performance tests	No	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes	
§ 63.7(f)	Alternative test method provisions	Yes	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes	
§ 63.7(h)	Waiver of tests	Yes	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No	
§ 63.8(b)(1)	Monitoring	Yes	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes	
§ 63.8(c)(1)	Monitoring system	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
	operation and maintenance		
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS. Except that § 63.8(e) only applies as specified in § 63.6645.
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved. Except that § 63.9(b) only applies as specified in § 63.6645.
§ 63.9(c)	Request for compliance	Yes	Except that § 63.9(c) only applies as

General provisions citation	Subject of citation	Applies to subpart	Explanation
	extension		specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use. Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved. Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes	
§ 63.9(j)	Change in previous information	Yes	
§ 63.9(k)	Electronic reporting procedures	Yes	Only as specified in §§ 63.9(j), 63.6620, 63.6625, 63.6645, and 63.6650.
§ 63.10(a)	Administrative provisions for recordkeeping/ reporting	Yes	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes	
§	Record when under	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
63.10(b)(2)(xii)	waiver		
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§ 63.10(b)(3)	Records of applicability determination	Yes	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes	
§ 63.10(d)(2)	Report of performance test results	Yes	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	No	Excess emissions and exceedance reporting is specified in § 63.6650.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/ reporting	Yes	
§ 63.11	Flares	No	
§ 63.12	State authority and delegations	Yes	
§ 63.13	Addresses	Yes	
§ 63.14	Incorporation by reference	Yes	
§ 63.15	Availability of information	Yes	

[89 FR 70522, Aug. 30, 2024]

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 ***Measurement System.*** The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 ***Data Recorder.*** A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 ***Electrochemical (EC) Cell.*** A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 ***Interference Gas Scrubber.*** A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 ***Moisture Removal System.*** Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 ***Sample Interface.*** The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 ***Nominal Range.*** The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 ***Calibration Gas.*** A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 ***Zero Calibration Error.*** The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 ***Up-Scale Calibration Error.*** The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 ***Interference Check.*** A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 ***Repeatability Check.*** A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 ***Sample Flow Rate.*** The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 ***Sampling Run.*** A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 ***Sampling Day.*** A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 ***Pre-Sampling Calibration/Post-Sampling Calibration Check.*** The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 ***Performance-Established Configuration.*** The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 ***Sample Probe.*** A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 ***Sample Line.*** Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 ***Calibration Assembly (optional).*** A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 ***Particulate Filter (optional).*** Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 ***Sample Pump.*** A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 ***Sample Flow Rate Monitoring.*** An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 ***Sample Gas Manifold (optional).*** A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 ***EC cell.*** A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 ***Data Recorder.*** A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 ***Interference Gas Filter or Scrubber.*** A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 ***Calibration Gases.*** CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 ***Up-Scale CO Calibration Gas Concentration.*** Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 ***Up-Scale O_2 Calibration Gas Concentration.***

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 ***Zero Gas.*** Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 ***Selection of Sampling Sites.***

8.1.1 ***Control Device Inlet.*** Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 ***Exhaust Gas Outlet.*** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 ***Stack Gas Collection and Analysis.*** Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O_2 concentrations.

8.3 ***EC Cell Rate.*** Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 ***Pre-Sampling Calibration.*** Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 ***Zero Calibration.*** For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 ***Zero Calibration Tolerance.*** For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 ***Up-Scale Calibration.*** Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 ***Up-Scale Calibration Error.*** The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 ***Post-Sampling Calibration Check.*** Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 ***Measurement Data Phase Performance Check.*** Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 ***Interference Check.*** Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 ***Interference Response.*** The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 ***Repeatability Check.*** Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 ***Repeatability Check Procedure.*** Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 ***Repeatability Check Calculations.*** Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) ***"Development of an Electrochemical Cell Emission Analyzer Test Protocol"*** , Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) ***"Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers"*** , EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) ***"ICAC Test Protocol for Periodic Monitoring"*** , EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) ***"Code of Federal Regulations"*** , Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility__________ Engine I.D.__________ Date______

Run Type:	(_)	(_)	(_)	(_)
(X)	Pre-Sample Calibration	Stack Gas Sample	Post-Sample Cal. Check	Repeatability Check

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
"											
"											
"											
"											
Measurement Data Phase											
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Mean											
Refresh Phase											
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[78 FR 6721, Jan. 30, 2013]