

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION**

MEMORANDUM

September 24, 2026

TO: Lee Warden, P.E., Chief Engineer

THROUGH: Rick Groshong, Compliance and Enforcement Group Manager

THROUGH: Joseph K. Wills, P.E., Engineering Manager, Permitting Section

THROUGH: Junru Wang, P.E., Existing Source Permits Section

FROM: Elijah Ecklund, E.I., Engineering Section, ROAT

SUBJECT: Evaluation of Application No. **2019-0607-C (M-3) PSD**
Public Service Company of Oklahoma
Northeastern Power Station (SIC 4911/NAICS 221112)
Facility ID No: 212
Latitude: 36.43783°N, Longitude: 95.70537°W
Section 4, Township 22N, Range 15E, Rogers County, Oklahoma
Directions: From US 169 and OK 88, approximately one mile south of
Oologah, head east on OK 88 roughly 200 yards and turn south into facility.

SECTION I. INTRODUCTION

Public Service Company of Oklahoma (PSO or the applicant) has submitted an application for a modification to their construction permit for their Northeastern Power Station. The facility is currently operating under Permit No. 2019-0607-TVR3, issued on August 24, 2022 and Permit No. 2019-0607-C (M-1), issued March 9, 2026.

The total emissions from the facility are above the major source thresholds. This facility, therefore, is subject to Title V permitting requirements and is considered a “major” source. The facility is a major source for PSD and is a major source of HAPs.

SECTION II. REQUESTED CHANGES

PSO is requesting the following changes to their Northeastern Power Station facility:

- 1.) Replacement of the burner on Auxiliary Boiler 3.
- 2.) A condition for a 26% annual capacity factor limitation for Auxiliary Boiler 3 (Equivalent to 544,346 MMBTU/YR of natural gas consumed or 2,277 hours per year at the maximum heat input) added to Specific Condition 1.d.
- 3.) Installation of two natural gas-fired simple cycle combustion turbines (SCCTs) and two associated natural gas-fired fuel gas heaters (FGHs).

- 4.) A condition for a 33.33% annual capacity factor limitation for the two SCCTs and the two associated FGHs (Equivalent to 6,685,619.5 MMBTU/YR of natural gas consumed for the turbines (each) and 7,300 MMBTU/YR of natural gas for the heaters (each), or 2,920 hours per year (each) at the maximum heat input) added as Specific Conditions 1.g.i and 1.h.i, respectively.
- 5.) Replacement of Auxiliary Boiler 1/2 with a 276.5 MMBTUH boiler.
- 6.) A condition for a 21% annual capacity factor limitation for Auxiliary Boiler 1/2 (Equivalent to 508,649 MMBTU/YR of natural gas consumed or 1,840 hours per year at the maximum heat input) added as Specific Condition 1.c.i.
- 7.) EUG-Aux 1/2 has been renamed to EUG-Aux 2. Auxiliary Boiler 1/2 has been renamed to Auxiliary Boiler 2.

Changes 1 and 2 were requested in the application for 2019-0607-C (M-2), changes 3 and 4 were requested in the application for 2019-0607-C (M-3) PSD, and changes 5 through 7 were requested in the application for 2019-0607-C (M-4). All requested changes will be consolidated and integrated into this construction permit.

The requested changes in Permit No. 2019-0607-C (M-1) have already been issued as of March 9, 2026. Per Section III of this memorandum, it was found that the changes in Permit No. 2019-0607-C (M-1) (Unit 2 burner modification and continuation of Unit 3 on natural gas) and Permit Application No. 2019-0607-C (M-2) (Auxiliary boiler 3's burner replacement) were to be aggregated. For PSD review, these two projects will be reviewed as a single project.

The emission factors listed for EUG-01 were given in ppm, which have been updated to lb/MMBTU. Additionally, the methodology for calculating SO₂ and H₂SO₄ emissions from turbines Unit 1A and Unit 1B (EUG-01) in issued Permit No. 2019-0907-C (M-1) incorrectly used a sulfur limit of 5 gr/100 SCF for the hourly limit. Per Permit No. 2012-918-TVR2 (M-1), this limit was changed to 0.25 gr/100 SCF. This has been updated to the correct sulfur limit of 0.25 gr/100 SCF. The calculated emission rates remain the same.

The permit has been updated to the latest State of Oklahoma rules and federal regulations. Emissions factors and calculations have also been updated to reflect the most recent AP-42 and DEQ guidance.

SECTION III. PROJECT AGGREGATION

From May 1, 2025, to December 1, 2025, PSO has submitted four air permit applications, summarized below:

- 1.) 2019-0607-C (M-1) authorized continuing operation of Unit 3 while establishing an off-setting emission reduction per the Second Amended Regional Haze Agreement (SARHA) that limited emissions of NO_x to 300 TPY for Unit 3 and 5,530 TPY for Unit 2 as well as authorized modifications to Unit 2 burners.
- 2.) 2019-0607-C (M-2) was to authorize the replacement of the burner on Auxiliary Boiler 3.
- 3.) 2019-0607-C (M-3) PSD was to authorize the construction of two new combustion turbines, Units 5 and 6, and supporting equipment.

4.) 2019-0607-C (M-4) was to authorize the replacement of Auxiliary Boiler 2.

Per the 2009 NSR Aggregation Action, “whether a physical or operational change is dependent on another for its viability is still a relevant factor in assessing whether the changes should be aggregated,” and “substantially related activities are likely to be jointly planned (i.e., part of the same capital improvement project or engineering study), and occur close in time and at components that are functionally interconnected.”

The requested changes in the permit applications M-1 and M-2 were found to be technically and economically dependent and substantially related, but independent from M-3 and M-4. M-1 requests the continued operation of Unit 3 (along with the establishment of SARHA for Unit 2 and 3 and Unit 2’s gas burner modification), with M-2 requesting a modification to Auxiliary Boiler 3’s burners to continue reliable support for Unit 3. As such, M-1 and M-2 will be aggregated together as one project when conducting PSD review.

The requested changes in the permit application M-3 were found to be technically and economically independent and not substantially related to any other projects. M-3 requests the construction of Unit 5 and 6 to provide extra generation capacity. These new units operate independently of the other units. As such, M-3 is not aggregated with any other project.

The requested changes in the permit application M-4 were found to be technically and economically independent and not substantially related to any other projects. M-4 requests the replacement of Auxiliary Boiler 2, which supports Unit 2. While M-1 establishes an enforceable emission reduction for Unit 2, the emission rate change for Unit 2 is completely independent of Auxiliary Boiler 2. As such, M-4 is not aggregated with any other project.

SECTION IV. PSD REVIEW

The PSD applicability analysis requires Baseline Actual Emissions (BAE) to be compared to Potential to Emit (PTE) or Projected Actual Emissions (PAE). Subtracting PTE or PAE from BAE results in the project emissions increase (PEI). If the PEI exceeds a significant emission rate (SER), then further review is required.

Project 1

The requested changes in Permit No. 2019-0607-C (M-1) and the application for Permit 2019-0607-C (M-2) were determined to be related, and the combined project is reviewed here (Project 1). Project 1 is the continued operation of Unit 3, establishment of the SARHA requirements for Unit 2 and 3, Unit 2 burner replacement, and the replacement of the burner on Auxiliary Boiler 3.

Unit 3 is now capable of operating 100% on natural gas.

Emissions from natural gas fired fuel are less than the previous coal fired fuel, so for a conservative estimate, PAE is assumed to be equal to BAE, resulting in a PEI of zero for Unit 3.

Emissions from Unit 2 are based on using all relevant information, including but not limited to, historical operational data, the company’s own representations, the company’s expected business

activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved SIP. No changes in emissions are expected except for a decrease in NO_x and an increase in CO due to installing Lower NO_x burners. Therefore, VOC, PM_{10/2.5}, and SO₂ PAE are assumed to be equal to BAE because the emissions are based only on the usage of natural gas and the permit will limit the amount of natural gas combusted.

Per 2019-0607-C (M-1), a specific condition was established to reduce the allowable NO_x emission limit to 0.22 lb/MMBTU. As such, PAE of NO_x were reduced and were less than BAE. For the purpose of PSD applicability, PAE of NO_x for Unit 2 and Unit 3 were conservatively set equal to the BAE for Unit 2.

Emissions of CO for Unit 2 can be based on one of three options: 1) the average of the 2023 and 2024 stack test results (0.086 lb/MMBTU); 2) the applicable AP-42 factor (0.082 lb/MMBTU), or 3) the burner vendor's target value (0.074 lb/MMBTU based on 100 ppm @ 3% O₂). All three options result in emissions lower than BAE. For the purpose of PSD applicability, PAE of CO for Unit 2 were conservatively set to equal BAE.

PAE Estimates for CO

Options for PAE Estimates	Emission Rate (lb/MMBtu)	PAE (TPY)
Average of Stack Test Results	0.086	617.35
AP-42	0.082	594.62
Vendor Target Value	0.074	534.31

Unit 2 PAE Estimates

ID#	NO _x (TPY)	CO (TPY)	VOC (TPY)	PM _{10/2.5} (TPY)	SO ₂ (TPY)
Unit 3	1,495.8	634.3	36.68	50.85	4.33

Emissions of CO, VOC, PM, and SO₂ from Aux 3 are based on AP-42 (7/98), Section 1.4, a gas heating value of 1,020 BTU/SCF, a 26% annual capacity factor (2,277 hr/yr), and a rating that will not exceed 544,346 MMBTU/YR based on the 26% annual capacity factor. Emissions of NO_x are based on manufacture's specifications.

Aux 3 Emission Factors

ID#	NO _x	CO	VOC	PM _{10/2.5}	SO ₂
	lb/MMSCF	lb/MMSCF	lb/MMSCF	lb/MMSCF	lb/MMSCF
Aux 3	140	84	5.5	7.6	0.60

Aux 3 Emissions

ID#	Rating	NO _x	CO	VOC	PM _{10/2.5}	SO ₂
	MMBTU/YR	TPY	TPY	TPY	TPY	TPY
Aux 3	544,346 ⁽¹⁾	36.26	21.76	1.42	1.97	0.16

⁽¹⁾ Based on a 26% annual capacity factor.

Unit 2 PEI

Pollutant	2023	2024	BAE	PAE	PEI
NO _x	1,513.50	1,478.00	1,495.80	1,495.80	0.00
CO	330.99	937.7	634.3	634.3	0.00
VOC	36.48	36.89	36.68	36.68	0.00
PM _{10/2.5}	50.66	51.04	50.85	50.85	0.00
SO ₂	4.05	4.60	4.33	4.33	0.00

Aux 3 PEI

Pollutant	2023	2024	BAE	PAE	PEI
NO _x	5.89	5.89	5.89	36.26	30.37
CO	2.67	2.67	2.67	21.76	19.09
VOC	0.20	0.20	0.20	1.42	1.22
PM _{10/2.5}	0.27	0.27	0.27	1.97	1.70
SO ₂	0.02	0.02	0.02	0.16	0.14

Total PEI

Pollutants	Total PEI	PSD Threshold	PSD Required
NO _x	30.37	40	No
CO	19.09	100	No
VOC	1.22	40	No
PM	1.70	25	No
PM ₁₀	1.70	15	No
PM _{2.5}	1.70	10	No
SO ₂	0.14	40	No

The total PEI on all pollutants for Project 1 is less than the SER, thus not warranting any further review.

Project 2

The next project is the requested changes in Permit No. 2019-0607-C (M-3) (Project 2). Project 2 is the installation of two natural gas-fired simple cycle combustion turbines, and their associated natural gas-fired fuel gas heaters.

Emissions from SCCT 5 and SCCT 6 are based on the manufacturer's data used to establish the BACT emission limits. Maximum potential hourly emission rates were provided by GE for NO_x, CO, VOC, PM, PM₁₀, PM_{2.5}, and GHG (as CO₂e). Emissions of SO₂ are based on the maximum fuel heat input of 2,289.67 MMBTUH and a maximum sulfur content of 0.5 gr S/100 scf. Emissions of H₂SO₄ are based on manufacturers data. Emissions of HAPs are based on emissions factors from AP-42 (4/00), Section 3.1.

Since it takes time to reach lean pre-mix mode, emissions from startup and shutdown, when the units are operated in diffusion mode, are also included for NO_x, CO, VOC, and PM_{10/2.5}. Since emissions of SO₂, H₂SO₄, GHG, and HAPs are based on amount of fuel combusted during SUSD, they are assumed to be no more than emissions from normal operations. It is estimated that there

will be 300 events each for the start up and shut down operations, or around 155 hours of uncontrolled emissions.

PSO proposes a 33.33% annual capacity factor limitation for SCCT 5 and SCCT 6, resulting in annual emissions being based on combustion of 6,685,619.5 MMBTU per year or an equivalent of 2,920 hours per year at the maximum heat input.

SCCT Emission Factors

Pollutant	Factor (lb/MMBTU)
NO _x	0.034
CO	0.0156
VOC	0.0015
SO ₂	0.0014
PM _{10/2.5}	0.0031
H ₂ SO ₄	0.00011
GHG	123.12

SCCT USD Emission Factors

Pollutant	18-minutes Startup Uncontrolled (lb/event)	13-minutes Shutdown Uncontrolled (lb/event)	Total SUSD (lb/event)
NO _x	57.8	31.9	89.70
CO	396.7	252.7	649.40
VOC	45.2	22.6	67.80

SCCT Emissions (Per Turbine)

ID#	NO _x (TPY)	CO (TPY)	VOC (TPY)	PM _{10/2.5} (TPY)	SO ₂ (TPY)	H ₂ SO ₄ (TPY)	GHG (TPY)
Normal	108.48	49.31	4.79	10.23	4.59	0.35	411,566
S/S	13.46	97.41	10.17	-	-	-	-
Total	121.94	146.73	14.96	10.23	4.59	0.35	411,566

Emissions of NO_x, CO, VOC, and PM from HTR 1 and HTR 2 are based on emission factors from the manufacturers data used to establish the BACT emission limits, a gas heating value of 1,020 BTU/SCF, and a rating of 2.5 MMBTUH. Emissions factors for SO₂ and GHG are based on AP-42 (7/98), Section 1.4.

PSO proposes a 33.33% annual capacity factor limitation for HTR 1 and HTR 2, resulting in annual emissions being based on combustion of 7,300 MMBTU per year or an equivalent of 2,920 hours per year at the maximum firing rate.

Heater Emission Factors

ID#	NO _x	CO	VOC	SO ₂	PM _{10/2.5}	GHG
	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU
HTR 1	0.011	0.0745	0.0149	0.0006	0.0081	117.65
HTR 2						

Heater Emissions

ID#	Rating	NO _x	CO	VOC	SO ₂	PM _{10/2.5}	GHG
	MMBTUH	TPY	TPY	TPY	TPY	TPY	TPY
HTR 1	2.5 ⁽¹⁾	0.04	0.27	0.05	<0.01	0.03	429.41
HTR 2	2.5 ⁽¹⁾	0.04	0.27	0.05	<0.01	0.03	429.41

⁽¹⁾ Annual Emissions are based on a 33.33% annual capacity factor.

The proposed project involves only the construction of new emissions units; therefore, all BAE are zero. Emissions from startup and shutdown operations are also included in the total PEI.

Total PEI

ID#	NO _x (TPY)	CO (TPY)	VOC (TPY)	PM _{10/2.5} (TPY)	SO ₂ (TPY)	H ₂ SO ₄ (TPY)	GHG (TPY)
SCCT 5	121.94	146.73	14.96	10.23	4.59	0.35	411,566
SCCT 6	121.94	146.73	14.96	10.23	4.59	0.35	411,566
HTR 1	0.04	0.27	0.05	0.03	<0.01	<0.01	429.41
HTR 2	0.04	0.27	0.05	0.03	<0.01	<0.01	429.41
Total PEI	243.96	294.00	30.02	20.52	9.18	0.70	823,990

The total PEI for Project 2 is above the major source thresholds for the following pollutants shown in the table below.

Pollutants	Total PEI	PSD Threshold	PSD Required
NO _x	243.96	40	Yes
CO	294.00	100	Yes
VOC	30.02	40	No
PM	20.52	25	No
PM ₁₀	20.52	15	Yes
PM _{2.5}	20.52	10	Yes
SO ₂	9.18	40	No
H ₂ SO ₄	0.70	7	No
GHG	823,990	75,000	Yes

As shown, PSD review is required for NO_x, CO, PM_{10/2.5}, and GHG for Project 2.

Project 3

The next project is the requested changes in Permit No. 2019-0607-C (M-4) (Project 3). Project 3 is the replacement of Auxiliary Boiler 2.

Emissions from Aux 2 are based on manufactures data, a 21% annual capacity factor and combustion of 508,650 MMBTU per year or an equivalent of 1,840 hr/yr at the maximum firing rate.

Aux 2 Emission Factors

ID#	NO _x	CO	VOC	PM _{10/2.5}	SO ₂
	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU
Aux 2	0.15	0.296	0.005	0.02	0.0014

Aux 2 Emissions

ID#	Rating	NO _x	CO	VOC	PM _{10/2.5}	SO ₂
	MMBTUH	TPY	TPY	TPY	TPY	TPY
Aux 2	276.5 ⁽¹⁾	38.15	75.28	1.27	5.09	0.36

⁽¹⁾ Annual emissions based on a 21% annual capacity factor.

The proposed project involves replacement of an existing unit and the new unit meets the definition of replacement unit. However, BAE is conservatively assumed to be zero.

Pollutants	Total PEI	PSD Threshold	PSD Required
NO _x	38.15	40	No
CO	75.28	100	No
VOC	1.27	40	No
PM	5.09	25	No
PM ₁₀	5.09	15	No
PM _{2.5}	5.09	10	No
SO ₂	0.02	40	No

The total PEI on all pollutants for Project 3 is less than the SER, thus not warranting any further review.

SECTION V. BACT ANALYSIS – PROJECT 2

Any major modification subject to PSD review must conduct an analysis to ensure the use of best available control technology (BACT) for each new or physically modified emission unit for each pollutant that exceeds an applicable PSD SER. The requirement to conduct a BACT analysis is set forth in the EPA and DEQ PSD regulations. The EPA regulations define BACT as:

an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.

In certain situations, as described below, BACT can be a standard other than an emission limitation.

If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements. First, the BACT analysis must include consideration of the most stringent available technologies. Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts contained in the record of the permit decision.

The purpose of a BACT analysis is to determine the lowest emission rate achievable while balancing the considerations of technical feasibility, energy impacts, and economics. In the 1987 policy memorandum, titled Transmittal of Background Statement on "Top-Down" BACT, EPA stated its preference for a top-down approach to BACT analyses. Under the top-down approach, the most stringent control available for a similar or identical source or source category is identified and a determination of feasibility is made. If the top level of control is determined to be infeasible because of technical, economic, environmental, or energy related reasons, then the next most stringent control option is evaluated. This process continues until the BACT level under consideration cannot be eliminated. Presented below are the five basic steps of a top-down BACT review procedure according to the *New Source Review Workshop Manual*:

Step 1: Identify all control technologies. The first step in the BACT analysis is to identify all control technologies for each pollutant. Available control options are those with a “practical potential for application” to the emission unit and pollutant under evaluation.

Step 2: Eliminate technically infeasible options. The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated. EPA states the following with regard to technical feasibility: “A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.”

Step 3: Rank remaining control technologies by control effectiveness. The control technologies are then ranked in order of effectiveness. If only one option remains or if all remaining options are equivalent, then ranking is not required.

Step 4: Evaluate most effective controls and document results. The remaining control technologies are evaluated on the basis of economic, energy, and environmental considerations.

Step 5: Select BACT. The first four steps involve the evaluation of control technologies, but the selection of BACT involves an evaluation of achievable emission rates. The selected BACT emission rate is enforced as an emission standard unless technological or economic limitations would make the imposition of an emission standard infeasible, in which case a design, equipment, work practice, or operational standard can be imposed.

Lastly, if a source is subject to an NSPS, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to the NSPS emission rate. In other words, the applicable NSPS limit represents the maximum allowable emission limit (or ceiling) for an emission source.

A review of recently issued air permits and related permit files and a search of the RBLC database was conducted in September 2025 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed project. To ensure that the units being reviewed were comparable in size to the turbine units proposed for installation at PSO, the following search criteria were used:

Permit Data between 01/2015 and 09/2025:

- Process Types:
 - 15.110 Large (>25 MW) Natural Gas Simple Cycle Combustion Turbines.
 - 15.150 Large (>25 MW) Other Gaseous Fuel and Gaseous Fuel Mixtures Simple Cycle Combustion Turbines.
 - 15.900 Large (>25 MW) Unknown Fuel and/or Cycle Combustion Turbines.
 - 19.700 Miscellaneous

A review was conducted for the proposed fuel gas heaters based on the following search criteria:

Permit Data between 01/2015 and 09/2025:

- Process Types:
 - 19.600 – Misc. Boilers, Furnaces, Heaters

PSO is proposing to install the following:

- Two 229-MW GE natural gas-fired SCCTs equipped with DLN
- Two 2.5-MMBtu/hr natural gas-fired fuel gas heaters.

The BACT selections are based on these design constraints, and any potential control methods that would require PSO to redefine these sources were not considered. The current baseline for SCCT >850 MMBtu/hr based on NSPS Subpart KKKKa is 25 ppmv at 15 percent O₂ (or 0.092 lb-NO_x/MMBtu or 0.83 lb-NO_x/MWh-gross or 0.85 lb-NO_x/MWh-net) with a utilization rate ≤45 percent and with design efficiency ≥38 percent. Anything above this is not reviewed.

The RBLC entries have been summarized in the tables found in Appendix A of this memorandum.

SECTION V.1 BACT ANALYSIS FOR SCCT

Project 2 contains two SCCT. For the purpose of evaluation, general information that applies to the SCCTs is presented only once (i.e., formation of NO_x, identifying potential control options, determining technical feasibility, and ranking of the remaining control options).

SECTION V.1.1 NO_x BACT - SCCT

The three most important pathways of NO_x formation from turbine combustion processes are thermal NO_x, prompt NO_x, and fuel NO_x. For natural gas-fired units, most NO_x is derived from thermal NO_x.

Thermal NO_x is formed mainly via the Zeldovich mechanism where the N₂ and oxygen (O₂) molecules in the combustion air react to form nitrogen monoxide (NO). Most thermal NO_x is formed in high temperature flame pockets downstream from the fuel injectors. Temperature is the most important factor, and at combustion temperatures above 2,370 °F, thermal NO_x is formed readily. Therefore, reducing combustion temperature is a common approach to reducing NO_x emissions.

Prompt NO_x, a form of thermal NO_x, is formed in the proximity of the flame front as intermediate combustion products such as hydrogen cyanide (HCN), N, and NH are oxidized to form NO_x. The contribution of prompt NO_x to overall NO_x is relatively small but increases in low-NO_x combustor designs. Prompt NO_x formation is also largely insensitive to changes in temperature and pressure.

Fuel NO_x forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x. With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little fuel bound nitrogen, fuel NO_x is not a major contributor to NO_x emissions from natural gas-fired combustion turbines.

In general, technology and emissions performance data could be limited to those turbines within the size range of typical simple-cycle units, and specifically the size of turbines proposed for installation by PSO. EPA has, in support of federal regulations such as the NSPS for combustion turbines (NSPS Subpart KKKK), reviewed the NO_x emissions performance data for combustion turbines of all sizes and found differing performance data for turbines based on the size of the unit. Per 70 FR 8318 (2/18/05): “We [EPA] identified a distinct difference in the technologies and capabilities between small and large turbines.”

EPA finalized NSPS Subpart KKKK with a breakpoint in consideration of turbine sizes greater than 850 MMBTUH, between 50 MMBTUH and 850 MMBTUH, and less than 50 MMBTUH. Since the proposed turbines are greater than 850 MMBTUH, only turbines in that range are truly comparable, since, as identified by EPA, there are inherent design differences in turbines based on size that can lead to differences in NO_x emission levels.

Step 1: Identify all control technologies:

NO_x reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_x formation (e.g., by reducing peak flame temperature) or introduce inerts (e.g., combustion products) that limit initial NO_x formation, or both. Several post-combustion NO_x control technologies could potentially be employed for the proposed turbines. These technologies use various strategies to chemically reduce NO_x to N₂ with or without the use of a catalyst.

Combustion control options include: Water or Steam Injection, Dry Low-NO_x (DLN) or Dry Low Emissions (DLE) Combustion Technology, and Good Combustion Practices.

Post-combustion control options include: EM_xTM /SCONO_xTM Technology, Selective Catalytic Reduction (SCR), SCR with Ammonia Oxidization Catalyst (Zero-SlipTM), Selective Non-Catalytic Reduction (SNCR), and Multi-Function Catalyst (METEORTM).

Each control technology is described in detail below:

- Water or Steam Injection:

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and reducing the formation of thermal NO_x. The water/steam injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids would damage the turbine due to erosion and/or the formation of deposits in the hot section of the turbine. Although water/steam injection can reduce NO_x emissions by up to 60%, the lower average temperature within the combustor may produce higher levels of CO and VOC as a result of incomplete combustion. Additionally, water/stream injection results in a decrease in combustion efficiency, an increase in power demand (due to increased mass flow), and an increase in maintenance requirements due to wear.

- DLN or DLE Combustion Technology:

DLN or DLE combustion technology, also referred to as lean premix technology, is a pollution prevention technology that minimizes NO_x emissions by reducing the conversion of atmospheric nitrogen to NO_x in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor. In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air decreases the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area.

Since NO_x formation rates are an exponential function of temperature, a considerable reduction in NO_x can be achieved by the lean pre-mix system. Depending on the manufacturer and product, different levels of control efficiencies can be achieved.

- Good Combustion Practices:

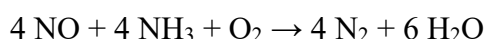
Good combustion practices are those that allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NO_x emissions include fuel characteristics and air-to-fuel ratios.

- EM_xTM /SCONO_xTM Technology:

EM_xTM (the second-generation of the SCONO_x NO_x Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia (NH₃). The SCONO_x system consists of a platinum-based catalyst coated with potassium carbonate [K₂(CO₃)] to oxidize NO_x (to potassium nitrate [K(NO₃)] and CO (to CO₂). Hydrogen (H₂) is then used as the basis for the catalyst regeneration process where K(NO₃) is reacted to reform the K₂(CO₃) catalyst and release nitrogen gas and water. The catalyst must be installed where the flue gas has a temperature range between 300 °F to 700 °F. The SCONO_x catalyst is susceptible to fouling by sulfur if the sulfur content of the flue gas is high. Estimates of control efficiency for a SCONO_x system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 78% for NO_x reductions down to 2.0 ppm, and even higher NO_x reductions down to 1 ppm for some designs.

- SCR:

SCR is a post-combustion gas treatment process in which NH₃ is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH₃ and NO react to form diatomic N₂ and H₂O vapor. The overall chemical reaction can be expressed as:



When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent. Optimal temperatures for SCR units range from 480 °F to 800 °F, and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200 °F. Other considerations include the possibility for ammonia slip, which refers to emissions of unreacted ammonia escaping with the flue gas and its contribution to secondary particulate formation.

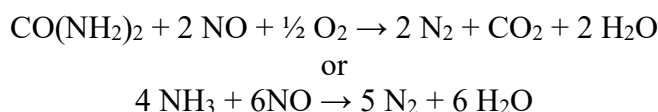
- SCR with Zero-SlipTM:

SCR with Ammonia Oxidation Catalyst (Zero-SlipTM) is a refinement on standard post-combustion SCR technology developed by Cormetech and Mitsubishi Power Systems to reduce ammonia slip associated with traditional SCR systems. The Zero-SlipTM

technology consists of a second bed of catalyst that is installed after the main SCR catalyst to further react NO_x with the ammonia. This results in NO_x emissions on par with standard SCR systems and less ammonia slip (less than 2.0 ppmvd at 15% O₂).

- SNCR:

SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia with NO_x. In the SNCR chemical reaction, urea [CO(NH₂)₂] or NH₃ is injected into the combustion gas path to reduce the NO_x to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:



Typical removal efficiencies for SNCR range from 30 to 50 percent, or higher when coupled with combustion controls. An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 °F to 2,000 °F. Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_x. The temperature range required for effective operation of SCNR is far greater than the peak exhaust temperature for the proposed turbines.

- METEORTM:

METEORTM is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc. and optimized by Cormetech. The METEORTM catalyst uses ammonia, similar to standard SCR systems, to reduce NO_x emissions but is also able to reduce CO, VOC, and NH₃ emissions using a single catalyst bed (i.e., it eliminates the need for a separate oxidation catalyst system if CO and VOC reductions are required), resulting in reduced pressure drop and parasitic load requirements. The ability of the METEORTM catalyst to reduce NO_x emissions is on par with traditional SCR designs.

Step 2: Eliminate technically infeasible options:

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

- Water or Steam Injection: [Not Feasible]

Water or steam injection is a NO_x reduction technology that is commonly used to control NO_x emissions when fuel oil is burned, but is not as effective as DLN/DLE combustors when firing natural gas. Water or steam injection also cannot be used in conjunction with DLN/DLE because it leads to unstable combustion and increases CO emissions. Because the proposed turbines will utilize DLN that reduce NO_x emissions further than water or steam injection would and the two options are mutually exclusive, water or steam injection is deemed to be technically infeasible.

- DLN or DLE Combustion Technology: [Feasible]

DLN/DLE combustion technology is a NO_x control technology that is integral to a combustion turbine. DLN/DLE are technically feasible for the turbine.

- Good Combustion Practices: [Feasible]

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the turbines.

- EM_xTM /SCONO_xTM Technology: [Not Feasible]

EM_xTM /SCONO_xTM catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_x, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_xTM /SCONO_xTM catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation. Additionally, the operating range of the catalyst is well below the exhaust temperature for simple-cycle combustion turbines. Consequently, EM_xTM /SCONO_xTM is not technically feasible for the proposed simple-cycle combustion turbines.

- SCR: [Feasible]

Optimal temperatures for the operation of SCR range from 480 °F to 800 °F. The proposed new turbines are expected to have exhaust temperatures of greater than 800 °F, which is outside the optimal operating temperature range. However, while the exhaust temperature of the proposed turbines is outside the typical temperature range, PSO is not removing SCR from consideration based on technical feasibility.

- SCR with Zero-SlipTM: [Not Feasible]

Based on the review of available control technologies, to date, the Zero-SlipTM catalyst technology has not been demonstrated on large, utility-size units, with full scale

operation demonstrated on a 7.5 MW Solar Taurus combustion turbine. In addition, this technology is essentially SCR with a focus on reducing ammonia slip. Accordingly, as this technology has not been demonstrated on large, utility size units, and it would not achieve NO_x emission rates lower than that achieved by conventional SCR designs, the ZeroSlip™ technology option is not considered a technically feasible control option.

- SNCR: [Not Feasible]

The temperature range required for effective operation of this technology, 1,600 °F to 2,000 °F, is far greater than the peak exhaust temperature for the proposed turbines. In addition, a review of the RBLC database and AP-42's supplemental database for Chapter 3.1, Stationary Gas Turbines, April 2000, shows that SNCR has not been demonstrated on turbine of the nature proposed by PSO. Given that the changes to adapt units for use of SNCR, such as adding a flue gas heater, are not practical and would reduce the energy efficiency of the generating units, SNCR is eliminated as a technically feasible option for control of NO_x emissions from the proposed turbines.

- METEOR™: [Not Feasible]

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320-MW Siemens/Westinghouse 501G combustion turbine installed in November 2015. A review of the RBLC database for turbines similar to the proposed units did not return any units that use the METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst, the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below

Control Technology	Rank	Estimated Efficiency
SCR	1	70-90%
DLN/DLE Combustion Technology	2	Base Case
Good Combustion Practice	3	Base Case

Step 4: Evaluate most effective controls and document results:

Based on the cost of control estimated using EPA's June 2019 Air Pollution Control Cost Estimation Spreadsheet for SCR, this control option is economically infeasible for the proposed SCCT units 5 and 6. The cost analysis is summarized below:

Total Capital Investment (TCI)	
Parameter	Data
Maximum Annual MW Output, B _{MW}	229-MW

Parameter	Data
Elevation Factor, ELEVF	1.02
Retrofit Factor, RF	0.80
Equation for Oil and Natural gas-fired Utility boilers between 25 and 500 MW:	$TCI = 86,380 \cdot (200/B_{MW})^{(0.35)} \cdot B_{MW} \cdot ELEVF \cdot RF$
CEPCI for 2024	796.16
CEPCI for 2016	541.7
TCI, in 2024 dollars	\$22,685,039

Annual Cost Parameters

Parameter	Data
Reagent Usage, m_{sol}	95 lb/hr
Reagent, $Cost_{reag}$	0.293 \$/gal
Total Operating Time, t_{op}	2891 hr
Electricity Consumption, P	1282.71 kW
Electricity, $Cost_{elect}$	0.0361 \$/kWh
Number of SCRs, n_{scr}	1
Catalyst Volume, Vol_{cat}	59,850.49 ft ³
Catalyst Cost, $CC_{replace}$	227 \$/ft ³
Number of catalyst layers, R_{layer}	3
Future Worth Factor, FWF	0.0975
Operator Cost, OC	60 \$/hr
Operator Hours, OH	480 hr/yr
Capital Recovery Factor, CRF	0.0806

Direct Annual Cost (DAC)

Direct Cost	Equation	In 2024 dollars (\$/yr)
Maintenance	$0.005 \cdot TCI$	113,425
Reagent	$m_{sol} \cdot Cost_{reag} \cdot t_{op}$	10,708
Electricity	$P \cdot Cost_{elect} \cdot t_{op}$	133,870
Catalyst Replacement	$n_{scr} \cdot Vol_{cat} \cdot (CC_{replace}/R_{layer}) \cdot FWF$	445,424
Total DAC		703,427

Indirect Annual Cost (IDAC)

Indirect Cost	Equation	In 2024 dollars (\$/yr)
Administrative	$0.03 \cdot (OC \cdot OH + 0.4 \cdot \text{Maintenance})$	2,225
Capital Recover	$CRF \cdot TCI$	1,828,414
Total IDAC		1,830,639

Total Annual Cost (TAC)

Cost	In 2024 dollars (\$/yr)
Direct	703,427
Indirect	1,830,639
Total	2,534,067

The amount of NO_x removed with the SCR would be 102 TPY. With an annual upkeep cost of \$2,534,067, the cost effectiveness would be \$24,826 per ton of NO_x removed. The estimated cost effectiveness is greater than \$20,000 per ton of NO_x removed, making the SCR economically infeasible.

Step 5: Select BACT:

PSO proposes the use of DLN and good combustion practices as BACT for the GE SCCTs. Review of the RBLC entries confirms that controls for NO_x emissions on units of similar sizes are typically DLN (for natural gas-fired units) and good combustion practices.

The proposed SCCTs will be subject to NSPS Subpart KKKKa. NSPS Subpart KKKKa does not require SCR and includes a NO_x emission standard for simple cycle operation for natural gas combustion of 25 ppm at 15% O₂ on a 4-hour rolling average (or 0.092 lb-NO_x/MMBtu or 0.83 lb-NO_x/MWh-gross or 0.85 lb-NO_x/MWh-net). NSPS Subpart KKKKa sets the floor of allowable NO_x BACT limits.

A review of the RBLC entries listed above provides an indication of what has been established for similar combustion turbines (simple-cycle turbines > 100 MW, ppmv based limits, combusting natural gas utilizing DLN and good combustion practices). The relevant RBLC entries are summarized in the table below.

RBLC ID	Facility Name	Size Rating	NO_x Emission Limit
IN-0384	Sycamore Riverside Energy LLC	240-MW	9 ppmv at 15% O ₂
AL-0329	Colbert Combustion Turbine Plant	229-MW	9 ppmv at 15% O ₂
TX-0819	Gaines County Power Plant	227.5-MW	9 ppmv at 15% O ₂
TX-0826	Mustang Station	162.8-MW	9 ppmv at 15% O ₂
TX-0975	Freestone Peakers Plant	221-MW	9 ppmv at 15% O ₂

BACT is to be set at the lowest value that is achievable. Since PSO is using BACT-level control technology, limits similar to those of comparably sized units should be achievable. Considering all the above factors, PSO proposed and the DEQ accepted as the BACT emission limit for NO_x for SCCT Unit 5 and Unit 6: 9 ppmvd at 15% O₂ (0.033 lb/MMBTU) on a 4-hour averaging basis when firing natural gas, excluding periods of startup and shutdown.

This matches the guarantee provided by the SCCT vendor, GE. Compliance will be demonstrated in accordance with NSPS Subpart KKKKa in Section 40 CFR §60.4340a(a). A 4-hour averaging period as documented per a continuous emissions monitoring system (CEMS) is proposed for consistency with the NSPS Subpart KKKKa monitoring requirements and to ensure PSO's ability to demonstrate continuous compliance.

SECTION V.1.2 CO BACT - SCCT

CO from combustion turbines is a by-product of incomplete combustion. Conditions leading to incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion-temperature, reduced combustion gas residence time, and load reduction. In addition,

combustion modifications taken to minimize NO_x emissions may result in increased CO emissions.

Step 1: Identify all control technologies:

Candidate control options identified include the following: Catalytic Oxidation, EM_xTM/SCONO_xTM Technology, and Good Combustion Practices.

Each control technology is described in detail below:

- Catalytic Oxidation:

An oxidation catalyst is a post-combustion control technology that utilizes a catalyst to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to form CO₂ and H₂O.

- EM_xTM/SCONO_xTM Technology:

EM_xTM (the second-generation of the SCONO_x NO_x Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia (NH₃).

- Good Combustion Practices:

Proper equipment design, proper operation, and good combustion practices serve to minimize incomplete combustion and the resulting formation of CO. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperatures as well as turbulence to mitigate incomplete mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on NO_x emissions. Accordingly, it is critical to optimize oxygen availability with input air while controlling temperature to minimize NO_x formation.

Step 2: Eliminate technically infeasible options:

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

- Catalytic Oxidation: [Feasible]

Oxidation catalysts are a control technology that is commonly found on combustion turbines. Oxidation catalysts are technically feasible for the turbine.

- EM_XTM/SCONO_XTM Technology: [Not Feasible]

The EM_XTM/SCONO_XTM catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_x, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_XTM/SCONO_XTM catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation. Additionally, the operating range of the catalyst is 300 °F to 700 °F, well below the exhaust temperature for simple-cycle combustion turbines. Consequently, it is concluded that EM_XTM/SCONO_XTM is not technically feasible for the proposed turbines.

- Good Combustion Practices: [Feasible]

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the turbines.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below

Control Technology	Rank	Estimated Efficiency
Catalytic Oxidization	1	67%
Good Combustion Practice	2	Base Case

Step 4: Evaluate most effective controls and document results:

Based on the cost of control estimated for Catalytic Oxidization, this control option is economically infeasible for the proposed SCCT units 5 and 6. The cost analysis is summarized below:

Total Capital Investment (TCI)	
Parameter	Data
Purchased Equipment Cost	\$4,400,000
Labor	\$2,000,000
TCI	\$6,400,000

Annual Cost Parameters

Parameter	Data
Recovery Period, yrs	30
Interest Rate, %	7
Capital Recovery Factor, CRF	0.0806

Direct Annual Cost (DAC)

Direct Cost	Source	Data
New Catalyst, \$	GE Vernova	2,000,000
Catalyst Replacement, \$	AEP Projects/Engineering	500,000
Replacement Frequency, yr	AEP Projects/Engineering	10
Total DAC, \$/yr		250,000

Indirect Annual Cost (IDAC)

Indirect Cost	Equation	In dollars (\$/yr)
Capital Recover	CRF*TCI	515,753
Total IDAC		515,753

Total Annual Cost (TAC)

Cost	In dollars (\$/yr)
Direct	250,00
Indirect	515,753
Total	765,753

The amount of CO removed with the Oxidization Catalyst would be 31.15 TPY. With an annual upkeep cost of \$765,753, the cost effectiveness would be \$24,580 per ton of CO removed.

The estimated cost effectiveness is greater than \$20,000 per ton of CO removed, making Catalytic Oxidation economically infeasible.

Step 5: Select BACT:

PSO is proposing good combustion practices as BACT for the GE SCCTs. Review of the RBLC entries confirms that BACT for CO emissions are typically good combustion practices.

The SCCTs will not be subject to any NSPS or NESHAP standard for CO; thus, there is no floor for an allowable CO limit.

The RBLC entries for similar units (simple-cycle turbines > 100 MW, ppmv based limits, combusting natural gas) utilizing good combustion practices are summarized in the table below:

RBLC ID	Facility Name	Size Rating	CO Emission Limit
IN-0384	Sycamore Riverside Energy LLC	240-MW	9 ppmv at 15% O ₂
AL-0329	Colbert Combustion Turbine Plant	229-MW	9 ppmv at 15% O ₂
TX-0733	Antelope Elk Energy Center	202-MW	9 ppmv at 15% O ₂
TX-0734	Clear Springs Energy Center	183-MW	9 ppmv at 15% O ₂

RBLC ID	Facility Name	Size Rating	CO Emission Limit
TX-0764	Nacogdoches Power Electric Plant	232-MW	9 ppmv at 15% O ₂
TX-0768	Shawnee Energy Center	230-MW	9 ppmv at 15% O ₂
TX-0769	Van Alstyne Energy Center	183-MW	9 ppmv at 15% O ₂
TX-0777	Union Valley Energy Center	183-MW	9 ppmv at 15% O ₂
TX-0788	Neches Station	232-MW	9 ppmv at 15% O ₂
TX-0794	Hill County Generation Facility	171-MW	9 ppmv at 15% O ₂
TX-0819	Gaines County Power Plant	227.5-MW	9 ppmv at 15% O ₂
TX-0975	Freestone Peakers Plant	221-MW	9 ppmv at 15% O ₂
TX-0986	Jack County Generation Facility	180.2-MW	9 ppmv at 15% O ₂

According to the manufacturer's guarantees, the GE SCCT's are capable of achieving 9 ppmvd at 15% O₂ with good combustion practices.

BACT is to be set at the lowest value that is achievable. Since PSO is using BACT-level control technology, limits similar to those of comparably sized units should be achievable. Considering all the above factors, PSO proposed and DEQ accepted as the BACT emission limit for CO: 9 ppmvd at 15% O₂ (0.0162 lb/MMBTU) on a 3-hour rolling averaging basis when firing natural gas, excluding periods of startup and shutdown

This matches the guarantee provided by the turbine manufacturer. PSO will demonstrate compliance with a CO CEMS.

SECTION V.1.3 PM₁₀ and PM_{2.5} BACT - SCCT

PM₁₀ and PM_{2.5} emissions from gas combustion result primarily from incomplete combustion and also ash and sulfur in the fuel. Combustion of pipeline-quality natural gas generates PM₁₀ and PM_{2.5} emissions in comparison to other fuels due to its low sulfur content. PM₁₀ and PM_{2.5} generally includes airborne particulate matter that passes through the inlet air filters, inert solids in the fuel supply, and metallic rust or oxidation products.

Step 1: Identify all control technologies:

The following are controls that reduce PM₁₀ and PM_{2.5}: Multicyclone, Wet Scrubber, Electrostatic Precipitator (ESP), Fabric Filter/Baghouse, Low Sulfur Fuel, and Good Combustion and Operating Practices.

Each control technology is described in detail below:

- Multicyclone:

Multicyclones consist of several small cyclones operating in parallel. The cyclones create a double vortex inside their shell, conveying centrifugal force on the inlet exhaust stream. The exhaust stream is then forced to move circularly through the cyclone, and the particulate matter in the stream is pushed to the cyclone walls. While this is effective for larger particles, smaller particles tend to be overtaken by the fluid

drag force of the air stream and will depart the cyclones with the exiting air stream. The particulate removal in cyclones can be improved by having more complex gas flow patterns. The control efficiency range for high efficiency single cyclones is 30 - 90% for PM_{10} and 20 - 70% for $PM_{2.5}$. The use of multicyclones leads to greater control efficiency than from a single cyclone, resulting in control efficiencies in the range of 80-95% for particles greater than 5 microns in diameter (PM_5). Multicyclones in parallel can typically handle a higher flowrate when compared to a single cyclone unit, up to approximately 106,000 standard cubic feet per minute (scfm). The allowable inlet gas temperature for a cyclone is limited by the type of construction material but can be as high as 540°C (1,000°F). Cyclones are generally used as pre-cleaners for final control devices such as fabric filters/baghouses or ESPs due to the lower control efficiency of smaller particles from a cyclone.

- Wet Scrubber:

Wet (in particular, venturi) scrubbers intercept dust particles using droplets of liquid (usually water). The larger particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The collection efficiencies of venturi scrubbers range from 70% to greater than 99%, depending on the application. Collection efficiencies are generally higher for PM with aerodynamic diameters of approximately 0.5 μm ($PM_{0.5}$) to 5 μm (PM_5). Inlet gas temperatures for wet scrubbers usually range from 4 °C to 400 °C (40 °F to 750 °F), with typical gas flowrates for single-throat scrubbers ranging from 500 to 100,000 scfm.

- Electrostatic Precipitator (ESP):

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, gas temperature, and plate dimensions. An ESP can be designed for either dry or wet applications. An ESP can generally achieve approximately 99 - 99.9% reduction efficiency for PM emissions. Typical ESPs can handle approximately 1,000 to 100,000 scfm, at high temperatures up to 700 °C (1,300 °F).

- Fabric Filter/Baghouse:

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower

pressure drops is the wear and tear on the bags suffered in the cleaning process. Typically, gas temperatures up to 260 °C (500 °F) can be accommodated routinely in a baghouse. The fabric filters have relatively high maintenance requirements (for example, periodic bag replacement), and elevated temperatures above the designed temperature can shorten the fabric life. Additionally, a baghouse/fabric filter cannot be operated in moist environments where the condensation of moisture could cause the filter to be plugged, reducing efficiency. Under the proper operating conditions, a baghouse can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.

Depending on the need, baghouses are available as standard units from the factory, or custom baghouses designed for specific applications. Standard baghouses can typically handle 100 to 100,000 scfm while custom baghouses are generally larger, ranging from 100,000 to over 1,000,000 scfm.

- Low Sulfur Fuel:

Combusting pipeline-quality natural gas with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form solid sulfates and other sulfur byproducts.

- Good Combustion and Operating Practices:

Good combustion and operating practices will minimize the formation of particulate emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

Step 2: Eliminate technically infeasible options:

All four of the add-on control technologies (multicyclones, wet scrubbers, ESPs, and baghouses) are technically infeasible for particulate from natural gas combustion. Although the add-on control technologies identified are utilized in a number of processes to control particulate emissions, none of these add-on control technologies are applicable to natural gas-fired combustion turbines. Combustion of pipeline quality natural gas generates relatively low levels of particulate emissions in comparison to other fuels due to the low sulfur content. In addition, turbines operate with a significant amount of excess air, which generates large exhaust flow rates. The low level of particulate emissions combined with the large exhaust gas volume results in very low concentrations of particulate.

Due to the low particulate concentration in the exhaust gas, add-on particulate controls would not provide any significant degree of emission reduction for the combustion turbines and are therefore not considered further in this analysis.

- Multicyclone: [Not Feasible]
- Wet Scrubber: [Not Feasible]
- Electrostatic Precipitator (ESP): [Not Feasible]

- Fabric Filter/Baghouse: [Not Feasible]
- Low Sulfur Fuel: [Feasible]
- Good Combustion Practices: [Feasible]

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below

Control Technology	Rank	Estimated Efficiency
Low Sulfur Fuel	1	Base Case
Good Combustion Practice	2	Base Case

Step 4: Evaluate most effective controls and document results:

Good combustion and operating practices with natural gas fuel is the most stringent PM₁₀ and PM_{2.5} control that is a technically feasible option. PSO will use pipeline-quality natural gas to lower the emissions of PM₁₀ and PM_{2.5}.

Step 5: Select BACT:

Review of the RBLC entries confirms that BACT for PM₁₀ and PM_{2.5} emissions are typically low-sulfur fuels and good combustion practices.

The RBLC entries listed in this section provides an indication of what has been established as BACT emission limitations for potentially similar units to those being proposed for installation by PSO. BACT limits for these entries are typically presented as separate limits on PM and PM₁₀/PM_{2.5}, although some entries include a limit on 'PM', 'PM₁₀', or 'PM_{2.5}' only.

There are four RBLC entries for simple-cycle units of comparable size with limits for PM₁₀/PM_{2.5} (including limits on only PM₁₀ or PM_{2.5}) summarized in the table below. These similar simple cycle combustion turbines have varying BACT limits, all based on pipeline-quality natural gas and good combustion practices.

RBLC ID	Facility Name	Size Rating	PM _{10/2.5} Emission Limit
AL-0329	Colbert Combustion Turbine Plant	229-MW	0.008 lb/MMBtu 18 lb/hr 3-hr avg
TX-0819	Gaines County Power Plant	227.5-MW	8.5 TPY
IN-0384	Sycamore Riverside Energy LLC	240-MW	0.0031 lb/MMBtu 6.6 lb/hr 3-hr avg
TX-0826	Mustang Station	162.8-MW	27 TPY

PSO proposed and the DEQ accepted the use of pipeline-quality natural gas and good combustion practices with an emission limit of 0.0031 lb/MMBtu on a 3-hr averaging basis as BACT for total PM₁₀ and total PM_{2.5}.

The turbine manufacturer provided total PM₁₀ and total PM_{2.5} emission rates for a variety of operational scenarios and has also provided guaranteed emission rates, which are based on the use of pipeline-quality natural gas. Initial compliance is to be demonstrated using stack testing using EPA Reference Method 5.

SECTION V.1.5 GREENHOUSE GASES (CO₂) BACT - SCCT

CO₂ production from combustion occurs by a reaction between carbon and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of CO₂ is emitted).

Step 1: Identify all control technologies:

Trinity reviewed the large body of information on GHG emissions from combustion turbines compiled from various rulemakings. The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. Based on the RBLC search, no add-on control methods for GHGs have been deemed BACT for any facility. Many of the RBLC entries list a variant of good combustion practices, efficient operation, state-of-the-art technology, or low emitting fuels (e.g., pipeline quality natural gas and ULSD). The following potential CO₂ control strategies were considered as part of this BACT analysis: Carbon Capture and Storage (CCS), Low Carbon Fuels, and Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices.

Each control technology is described in detail below:

- Carbon Capture and Storage (CCS):

CCS, also known as CO₂ sequestration, involves the cooling, separation, and capture of CO₂ emissions from the flue gas prior to being emitted from the stack, compression of the captured CO₂, transportation of the compressed CO₂ via pipeline, and finally injection and long-term geologic storage of the captured CO₂. For CCS to be technically feasible, all three components needed for CCS must be technically feasible: carbon capture and compression, transport, and storage.

The first phase in CCS is to separate and capture the CO₂ gas from the exhaust stream, and then to compress the CO₂ to a supercritical condition. Since most storage locations for CO₂ are greater than 800 meters deep, where the natural temperatures and pressures are greater than the critical point for CO₂, to inject CO₂ to those depths requires pressurizing the captured CO₂ to a supercritical state.

CO₂ capture can be performed via four main methods: absorption, adsorption, membranes, and cryogenic separation. The choice of the precise process varies with the properties of the exhaust stream. CO₂ separation has been well demonstrated in the oil and gas industries, but the characteristics of those streams are very different from a turbine system exhaust. Most combustion tests and projects have been on exhaust streams from coal combustion, which has more highly concentrated CO₂ than exhaust from natural gas combustion, or on natural gas combined-cycle systems. Existing CO₂

capture technologies have not been demonstrated in the context of capturing CO₂ from simple-cycle combustion turbines, regardless of industry use, as they have higher exit gas temperatures, lower exhaust gas CO₂ concentrations, and lower cycle efficiencies, all of which negatively affect the ability of the CCS systems to control CO₂ emissions.

Once separated, CO₂ must be compressed to supercritical conditions for transport and storage. There are no technical challenges with compressing CO₂ to those levels, but specialized technologies with high operating energy requirements are necessary. The CO₂ could be compressed to supercritical either before or after transport.

For phase two, CO₂ would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for CO₂ pipelines, particularly if supercritical CO₂ is being transported. Transport of CO₂ by pipeline is a demonstrated technology, but currently most CO₂ pipelines are in rural areas. Obtaining right-of-way in developed areas is difficult.

Various CO₂ storage methods have been proposed, though only geologic storage is achievable currently. Geologic storage involves injecting CO₂ into deep subsurface formations for long-term storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured CO₂ could also potentially be used for enhanced oil recovery via injection into oil fields.

- Low Carbon Fuels:

Hydrogen co-firing is being studied as a CO₂ emission reduction option available to gas-fired combustion turbines. Hydrogen does not contain carbon and therefore emits no CO₂ when combusted. As part of its rulemaking process for the proposed NSPS Subpart TTTTa, EPA evaluated the technical feasibility of hydrogen co-firing in combustion turbine electric generating units. EPA noted that there are several physical characteristics of hydrogen that differ from natural gas that make hydrogen co-firing challenging. One of the most significant differences identified by EPA is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane. A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components and increase thermal NO_x emissions. Furthermore, to achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas. Blending high volumes of hydrogen presents challenges with respect to turbine design capabilities and safety, as well as fuel availability and infrastructure (i.e., distribution, transportation pipelines, and storage).

EPA's Technical Support Document (TSD) included several examples of hydrogen co-firing demonstration projects that have been conducted on utility-sized gas turbines over the past several years. One example referenced in the TSD involved a demonstration test conducted by the Electric Power Research Institute (EPRI) at the New York Power Authority's Brentwood Site in September 2022. Tests were conducted to assess burning various hydrogen/natural gas fuel blends on a nominal 45

MW LM6000 gas turbine, and to identify the resulting impact on combustion turbine operation and CO₂, NO_x, and CO emissions. According to EPRI, the project demonstrated a 14 percent reduction in CO₂ emissions at a 35 percent hydrogen blend. However, during testing, gas turbine NO_x levels increased by up to 24 percent as the hydrogen fuel fraction increased. Increased NO_x emissions were controlled by increasing water injection (almost linearly with hydrogen fuel percentage) to maintain gas turbine outlet NO_x levels. Hydrogen co-firing was not performed during unit startup and shutdown operations.

In the Proposed NSPS Subpart TTTTa, EPA concluded that co-firing low-GHG hydrogen meets all of the statutory criteria for being adequately demonstrated as the best system of emission reduction (BSER) for application to gas-fired combustion turbines in that it has been demonstrated as technically feasible for new combustion turbines and EPA's expectation that adequate quantities of low-GHG hydrogen will be available by 2032 at a reasonable cost. Based on these findings, EPA proposed performance standards for the intermediate and base load combustion turbine subcategories based on co-firing low-GHG hydrogen as BSER. Although EPA proposed performance standards based on co-firing low-GHG hydrogen, EPA did not propose implementing the standards until 2032 due to limitations associated with the current availability of low-GHG hydrogen and hydrogen transportation, distribution, and storage infrastructure limitations.

While hydrogen creates no GHG emissions when it is combusted, emissions from the production and use of hydrogen can be significant. As such, significant GHG emission reductions would only be realized if combustion turbine electric generating units are able to co-fire low-GHG hydrogen. Low-GHG hydrogen is generally defined as hydrogen that is produced in a way that creates limited GHG emissions, generally by adding carbon capture and sequestration technology to fossil-based hydrogen production (e.g., natural gas reforming and coal gasification) or by generating the power needed for hydrogen production from a renewable resource. Currently, approximately 98 percent of hydrogen is made from fossil fuels with no CO₂ emissions control and would not qualify as low-GHG hydrogen. Significant advances in low-GHG production capabilities, such as electrolysis using renewable energy resources, are needed to provide the low-GHG hydrogen needed for electric power generation.

In addition to the existing supply limitations, combusting high volumes of hydrogen is currently limited due to inadequate hydrogen transportation and distribution transportation pipelines, and storage infrastructure. A viable hydrogen infrastructure requires that hydrogen be able to be delivered from where it is produced to the point of end use. That infrastructure also must be able to deliver hydrogen to the point of use at the times needed, requiring storage infrastructure. Infrastructure includes the pipelines, liquefaction plants, trucks, storage facilities, compressors, and dispensers involved in the process of delivering fuel. In addition, midstream infrastructure limitations and the adequacy and availability of hydrogen storage facilities currently present obstacles to the commercial availability and increase the price for delivered low-GHG hydrogen. These limitations, and the fact that building the infrastructure required to support low-

GHG hydrogen in the power sector will take place on a multi-year time scale, were part of the rationale for why the EPA did not propose hydrogen co-firing as BSER before 2032.

- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices:

As the baseline of most analyses, pollutant formation can be most cost-effectively minimized by efficient turbine design and good combustion, operating, and maintenance practices.

Within combustion units, operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Outside of the unit, energy loss can be minimized by providing sufficient insulation to the combustion units and associated duct work.

For the purposes of this GHG control technology assessment, it is important to note that good operating practices includes periodic maintenance. Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation.

Step 2: Eliminate technically infeasible options:

- Carbon Capture and Storage (CCS): [Not Feasible]

CCS involves cooling, separation, and capture of CO₂ from the flue gas prior to the flue gas being emitted from the stack, compression of the captured CO₂, transportation of the compressed CO₂ via pipeline, and finally injection and long-term geologic storage of the captured CO₂. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

It should be noted that there is little to no research that has been completed on the implementation of CCS systems on simple-cycle turbines. Though the lack of research is due to general industry understanding that it is impossible to utilize a CCS system on a simple-cycle turbine, the technical feasibility is still conservatively examined in this section. However, due to this lack of research on simple-cycle turbines, the technical feasibility in this section is completed using data collected on CCS systems installed on combined-cycle turbines.

- Carbon Capture:

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Currently, only two options appear to be feasible for the capture of CO₂ from the flue gas from the turbine systems: Post-Combustion Solvent Capture and Stripping and Post-

Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that “To date, all commercial post-combustion CO₂ capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents.”

A review of the U.S. Department of Energy’s (DoE) National Energy Technology Laboratory’s (NETL) research and development awards related to post-combustion capture of CO₂ indicates that moving from pilot scale tests at coal-fired power plants to large-scale commercial operations remains a focus; however, the existence of several Front End Engineering Design (FEED) studies indicates that commercial implementation is beginning to move forward. For example, a FEED study is underway for a commercial-scale carbon capture facility retrofitted at the Delta Energy Center in Pittsburg, CA, capable of capturing 2.4 MM tons of CO₂ per year. Another FEED study is underway for a 1.7 MM ton/yr CO₂ capture project at Louisville Gas And Electric Kentucky Utilities Cane Run #7.

Although FEED studies indicate heightened interest in exploring potential implementation opportunities for CCS, PSO is aware of only one successful CCS deployment on a combined-cycle combustion turbine facility. The Bellingham Energy Center captured CO₂ from a slipstream (i.e., a portion of the turbine exhaust stream) for use in the food industry and operated from 1991 to 2005. Additionally, a planned 2,000-MW natural-gas combined-cycle power plant with CCS is expected to come online towards the end of the 2020s, but construction is not expected to start for several years at least.

Presuming carbon capture is feasible, prior to sending the CO₂ stream to the appropriate storage site, it is necessary to compress the CO₂ from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO₂ would require a large auxiliary power load, resulting in additional fuel (and CO₂ emissions) to generate the same amount of power. The auxiliary power load could be handled by installation of a separate system to solely support CO₂ compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power needs of the compression system. This is often referred to as an “energy penalty” for operation of the CO₂ compression system and in effect can reduce the net CO₂ reduction of the CCS system.

- Carbon Transport:

The next step in CCS is the transport of the captured and compressed CO₂ to a suitable location for storage. This would typically be via pipeline. Pipeline transport is an available and demonstrated, although costly, technology. Short CO₂ pipelines have been constructed from power plants to proposed injection wells. However, these pipelines are dedicated use for the power plants and are unavailable for other industrial sites.

Since there are no other CO₂ pipelines in the area, PSO would need to construct a CO₂ pipeline to a storage location if it were to pursue carbon sequestration as a CO₂ control option. While it may be technically feasible to construct a CO₂ pipeline, considerations regarding the land use and availability need to be made. For the purposes of this analysis, it is conservatively assumed that a shortest distance pipeline can be built from a potential sequestration site to a potential carbon storage location. Realistically, a longer pipeline would be required to address land use and right-of-way considerations.

- Carbon Storage:

Capture of the CO₂ stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO₂ through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- Enhanced Oil Recovery (EOR): EOR involves injecting CO₂ into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO₂ in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO₂ would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO₂ would be stored in the depleted oil field.
- Saline Aquifers: Deep saline aquifers have the potential to store post-capture CO₂ deep underground below an impermeable cap rock.
- Un-Mineable Coal Seams: Additional storage is possible by injecting the CO₂ into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO₂ or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional methods of sequestration such as direct ocean injection of CO₂ and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for PSO to permanently store the captured CO₂.

PSO has concluded that CCS technology is not technically feasible at this time for simple cycle operations, based on the following key considerations:

- The simple cycle operations will involve frequent starts and stops and will have variable operating loads leading to variable CO₂ emissions.

- Solvent-based carbon capture systems have never been demonstrated for a simple-cycle combustion turbine and are generally considered infeasible for use in simple-cycle combustion turbines due to the low CO₂ concentration of the exhaust gas.
 - There are no existing or planned CO₂ pipelines within a reasonable distance from the proposed project.
 - There are no existing or planned commercially available sequestration sites within a reasonable distance from the proposed project which do not already have contractual agreements to meet their CO₂ sequestration needs.
- Low Carbon Fuels: [Not Feasible]

Hydrogen co-firing is a technically feasible CO₂ emission reduction strategy and has been demonstrated as technically feasible on gas-fired combustion turbines. However, due to limited availability of low-GHG hydrogen, and existing limitations of the hydrogen transportation, distribution, and storage system infrastructure, hydrogen co-firing, and specifically low-GHG hydrogen co-firing, is not an available CO₂ control option for the proposed combustion turbines. Adequate supplies of low-GHG hydrogen are not available to Northeastern, and an adequate and reliable supply of low-GHG hydrogen could not be delivered to the site without significant investment in hydrogen transportation/distribution infrastructure. For these reasons, co-firing low-GHG hydrogen is not an available GHG control technology for the proposed combustion turbines and will not be evaluated further as BACT.

- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices: [Feasible]

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, only Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices are technically feasible. Reduction efficiency is not applicable for this control method.

Step 4: Evaluate most effective controls and document results:

Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices for the combustion turbines was determined as the most stringent control method that is a technically feasible option.

Step 5: Select BACT:

The proposed combustion turbines will be subject to NSPS Subpart TTTTa, as finalized by EPA on April 25th, 2024. However, at the time of permit issuance, NSPS Subpart TTTTa is currently under review by EPA. If federal legislation, rulemaking, or a court ruling invalidates all, or part of, TTTTa, the invalidated portions will no longer be applicable through this permit. In the interim, DEQ will exercise enforcement discretion as appropriate. The NSPS includes CO₂ emission limits for combustion turbines, based on the annual capacity factor of the turbines, where capacity factor in this case means net electric sales as a percentage of potential electric output. The CO₂ emission limits are as follows:

- Base load combustion turbine:
 - Phase 1 (prior to January 2032): 800 to 1,250 lb CO₂/MWh-gross energy output, based on combined cycle operation;
 - Phase 2 (after December 2031): 100 to 150 lb CO₂/MWh-gross energy output, as determined by 40 CFR §63.5525a, based on carbon capture and sequestration;
- Intermediate load combustion turbine:
 - 1,170 - 1560 lb CO₂/MWh-gross energy output, as determined by 40 CFR §63.5525a, based on highly efficient generation; and
- Low Load combustion turbine:
 - 120 - 160 lb CO₂/MMBtu of heat input, as determined by 40 CFR §63.5525a, based on the use of clean fuels such as natural gas and hydrogen.

PSO understands that a BACT limit must be at least as stringent as the most stringent applicable federal or state regulation. In the event NSPS Subpart TTTTa is not overturned by SCOTUS or the rule is not repealed by EPA, PSO will comply with the applicable emission limits under the rule. If NSPS Subpart TTTTa is stayed or overturned by SCOTUS or repealed by EPA, then NSPS Subpart TTTTa is no longer the BACT floor.

PSO proposed and DEQ accepts as BACT efficient turbine design and operation and good combustion, operation, and maintenance practices along with a limit of 124.1 lb/MMBtu applicable as a rolling 12-month average as BACT for the SCCTs.

PSO proposed to demonstrate compliance using the procedures for estimating CO₂ mass emissions in 40 CFR Part 75 Appendix G.

SECTION V.1.6 GREENHOUSE GASES (CH₄) BACT - SCCT

CH₄ emissions from the natural gas combustion turbines form as a result of incomplete combustion of hydrocarbons present in the natural gas fuel.

Step 1: Identify all control technologies:

The only available control options for minimizing CH₄ emissions from the combustion turbine systems are efficient turbine operation coupled with good combustion, operating, and maintenance practices to minimize unburned fuel. Oxidation catalysts are not considered available for reducing CH₄ emissions because oxidizing the very low concentrations of CH₄ present in the combustion turbine exhaust would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts. For these reasons, catalyst providers do not offer products for reducing CH₄ emissions from gas-fired combustion turbines.

Step 2: Eliminate technically infeasible options:

- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices:
[Feasible]

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are the only technically feasible control options for reducing CH₄ emissions from the combustion turbines.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Good Combustion Practice	1	Base Case

Step 4: Evaluate most effective controls and document results:

No adverse energy, environment, or economic impacts are associated with efficient turbine operation and good combustion, operating, and maintenance practices for reducing CH₄ emissions from the combustion turbine.

Step 5: Select BACT:

Efficient turbine operation and good combustion, operating, and maintenance practices are the selected control options for minimizing CH₄ emissions from the combustion turbine systems.

PSO has determined that a numerical limit for CH₄ is unnecessary and that the work practices required for CO₂ BACT, and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for CH₄ BACT.

SECTION V.1.7 GREENHOUSE GASES (N₂O) BACT - SCCT

For the proposed project, the contribution of N₂O to the total CO₂e emissions is trivial and therefore should not warrant a detailed BACT review. Nevertheless, the additional information

provided supports the rationale that the proposed project meets BACT for contributions of N₂O as CO₂e.

A tradeoff between NO_x and N₂O emissions from the combustion turbines exists when developing a combustion control strategy, and this tradeoff influences the BACT selection process. There are five (5) primary pathways of NO_x production in gas-fired combustion turbine combustion processes: thermal NO_x, prompt NO_x, NO_x from N₂O intermediate reactions, fuel NO_x, and NO_x formed through reburning. For turbines using DLN combustors, the N₂O pathway is an important mechanism of NO_x formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with the N₂O molecule, creating N₂ and NO. In premixed gas flames, N₂O is primarily formed in the flame front or oxidation zone. Once formed, the N₂O is readily destroyed due to the relatively high concentration of H radicals; therefore, the N₂O emissions from premixed gas flames like DLN combustor flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms that decrease the H atom concentration in the N₂O formation zone can increase N₂O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream, which are all common NO_x control measures

Step 1: Identify all control technologies:

N₂O catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize N₂O emissions. Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with a N₂O catalyst followed by ammonia injection and a NO_x catalyst.

Step 2: Eliminate technically infeasible options:

- N₂O Catalysts: [Not Feasible]

N₂O catalyst providers do not offer products to control N₂O emissions from gas-fired combustion turbines due to the very low N₂O concentrations present in exhaust streams (approximately 5 ppm). In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N₂O concentration in the exhaust stream.

- Good Combustion, Operating, and Maintenance Practices: [Feasible]

With N₂O catalysts eliminated, good combustion practice is the only available control option. Good combustion practices are technically feasible control options for reducing N₂O emissions from the combustion turbines.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Good Combustion Practice	1	Base Case

Step 4: Evaluate most effective controls and document results:

As indicated in EPA's guidance on GHG BACT, GHG control strategies may have the potential to produce higher criteria pollutants as in the case of the competing NO_x and N₂O combustion control strategies for PSO's combustion turbine systems. In such cases, the guidance suggests that the applicant should consider the effects of increases in emissions of other regulated pollutants that may result from the use of that GHG control strategy, and based on this analysis, the permitting authority can determine whether or not the application of that GHG control strategy is appropriate given the potential increases in other pollutants.

Given the low N₂O emissions relative to NO_x emissions from the combustion turbine systems and EPA's continued concern over adverse impacts from ozone formation due to NO_x and VOC emissions, PSO does not consider it appropriate to control the combustion processes of the combustion turbine to specifically reduce N₂O emissions due to the counteractive increase in NO_x emissions. Therefore, good combustion practice for the specific purpose of minimizing N₂O formation is eliminated on the basis of adverse criteria pollutant impacts.

Step 5: Select BACT:

PSO has determined and DEQ accepts that a numerical limit for N₂O emissions is unnecessary and that the work practices required for CO₂ BACT, and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for N₂O BACT.

SECTION V.2 BACT ANALYSIS FOR FUEL GAS HEATER (FGH)

Project 2 contains two FGH. For the purpose of evaluation, general information that applies to the SCCTs is presented only once (i.e., formation of NO_x, identifying potential control options, determining technical feasibility, and ranking of the remaining control options).

SECTION V.2.1 NO_x BACT - FGH

The fuel gas heater produces NO_x as a byproduct of combustion. Various forms of NO_x emissions from combustion are covered in detail in Section V.1. The fuel gas heaters have a rated capacity of 2.5 MMBtu/hr. The RBLC was reviewed for all heaters that combusted natural gas or process gas and had a rated capacity of 50 MMBtu/hr or less. This 50 MMBtu/hr rating was selected based on engineering judgment, as heaters significantly larger than the proposed heater would not be directly comparable.

Step 1: Identify all control technologies:

Combustion control options include Good Combustion Practices (Base Case), Low NO_x Burners, and Flue Gas Recirculation (FGR).

Post-combustion control options include SCR and SNCR.

Each NO_x control technology is described in greater detail in Section V.1.1.

Each relevant control technology for the heaters is described in detail below:

- Good Combustion Practices:

Good combustion practices are those which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NO_x emissions include ambient temperature, limited nonemergency operation, fuel characteristics, and air-to-fuel ratios.

- Low NO_x Burners:

Low-NO_x burners employ multi-staged combustion to inhibit the formation of NO_x. Primary combustion occurs at lower temperatures under oxygen-deficient conditions; secondary combustion occurs in the presence of excess air.

- FGR:

FGR is a NO_x control measure that reduces the formation of thermal NO_x by reducing combustion temperature. The flame temperature is lowered by recirculating cooled flue gas and diluting the oxygen content of the combustion air.

- SCR:

SCR is a post-combustion gas treatment process in which NH₃ is injected into the exhaust gas upstream of a catalyst bed, as discussed in Section V.1.1.

- SNCR:

SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia with NO_x, as discussed in Section V.1.1.

Step 2: Eliminate technically infeasible options:

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

- Good Combustion Practices: [Feasible]

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the heater.

- Low NO_x Burners: [Feasible]

Low NO_x burners can achieve 30 ppm or even down to 9 ppm of NO_x. Low NO_x burners are considered technically feasible.

- FGR: [Not Feasible]

FGR has been demonstrated to be effective in reducing NO_x exhaust from combustion sources such as large heaters. However, there are no instances of FGR found in RBLC for heaters rated around 2.5 MMBtu/hr. The size of the heater and low flow rate would present challenges for any add-on controls, including FGR. Since it has not been demonstrated, FGR is considered technically infeasible.

- SCR: [Not Feasible]

SCR has been demonstrated to be effective in reducing NO_x exhaust from combustion sources such as natural gas fired engines. Optimal temperatures for the operation of SCR range from 480 °F to 800 °F and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200 °F. However, there are no instances of SCR found in RBLC for heaters less than 50 MMBtu/hr. The size of the heater and low flow rate would present challenges for any add-on controls, including SCR. Since it has not been demonstrated, SCR is considered technically infeasible.

- SNCR: [Not Feasible]

The temperature range required for effective operation of this technology, 1,600 to 2,000 °F, is far greater than the exhaust temperature for the proposed heater. In addition, a review of the RBLC database shows that SNCR has not been used on a heater of this size. The size of the heater and low flow rate would present challenges for any add-on controls, including SNCR. SNCR is eliminated as a technically feasible option for control of NO_x emissions from the proposed heater.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Low NO _x Burners	1	40%-85%
Good Combustion Practice	2	Base Case

Step 4: Evaluate most effective controls and document results:

None of the control options are eliminated based on an evaluation of collateral impacts or cost analysis.

Step 5: Select BACT:

PSO proposed the use of good combustion practices along with low NO_x burners and a NO_x BACT emission limit of 0.011 lb/MMBtu (9 ppm), based on data obtained from the manufacturer.

Based on review of the RBLC database, the proposed NO_x BACT limit is consistent with established limits for comparable natural gas-fired heaters. Given the size and intermittent operation of the fuel gas heater no source testing is needed.

SECTION V.2.2 CO BACT - FGH

CO from combustion turbines is a by-product of incomplete combustion.

Step 1: Identify all control technologies:

Candidate control options identified include the following: Catalytic Oxidation and Good Combustion Practices.

Each control technology is described in detail below:

- Catalytic Oxidation:

An oxidation catalyst is a post-combustion control technology that utilizes a catalyst to oxidize CO at lower temperatures, as discussed in Section V.1.2.

- Good Combustion Practices:

To minimize incomplete combustion and the resulting formation of CO, this control technology includes proper equipment design, proper operation, and good combustion practices.

Step 2: Eliminate technically infeasible options:

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

- Catalytic Oxidation: [Not Feasible]

Reviewing the RBLC, there are no instances of catalytic oxidizers on heaters of this size. This is likely due to the low flow rate and minimal CO emissions creating

challenges for any add-on controls. Since catalytic oxidation has not been demonstrated in practice, it is not technically feasible for the heater.

- Good Combustion Practices: [Feasible]

This represents the base case for design and operation of the heater.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Good Combustion Practice	1	Base Case

Step 4: Evaluate most effective controls and document results:

None of the control options are eliminated based on an evaluation of collateral impacts or cost analysis.

Step 5: Select BACT:

PSO proposed and the DEQ accepts good combustion practices as BACT with a CO BACT emission limit of 0.0745 lb/MMBtu, based on data obtained from the manufacturer.

Based on review of the RBLC database, the proposed CO BACT limit is consistent with established limits for comparable natural gas-fired heaters. Given the size and intermittent operation of the fuel gas heater, no source testing is needed.

SECTION V.2.3 PM₁₀ and PM_{2.5} BACT - FGH

Step 1: Identify all control technologies:

Using the RBLC search and permit review results, no potentially applicable PM₁₀/PM_{2.5} control technologies for natural gas-fired heaters were identified. The only available control option is combustion design controls.

Step 2: Eliminate technically infeasible options:

Combustion design controls are a technically feasible control option for reducing PM emissions from the heater.

- Good Combustion Practices: [Feasible]

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Good Combustion Practice	1	Base Case

Step 4: Evaluate most effective controls and document results:

The top and only available and technically feasible PM control option will be applied to achieve compliance with the proposed BACT limit.

Step 5: Select BACT:

PSO proposed and the DEQ accepted good combustion practices as BACT with a PM₁₀, and PM_{2.5} BACT emission limit of 0.0081 lb/MMBtu, based on data obtained from the manufacturer.

Based on review of the RBLC database, the proposed PM₁₀ and PM_{2.5} BACT limit is consistent with established limits for comparable natural gas-fired heaters. Given the size and intermittent operation of the fuel gas heater, no source testing is needed.

SECTION V.2.4 GREENHOUSE GASES (CO₂/CH₄/N₂O) BACT - FGH

CO₂ is by far the dominant GHG from this source. CH₄ and N₂O are present only in very small amounts, are incidental to combustion, and trend with the CO₂ emissions. This BACT analysis focused on CO₂ as a surrogate for all GHG emissions.

Step 1: Identify all control technologies:

The following potential control strategies were considered as part of this BACT analysis: O&M Practices, Efficient Burner Design, and Good Combustion Practices.

Step 2: Eliminate technically infeasible options:

All of the control techniques identified for small, natural gas-fired heaters are technically feasible

- O&M Practices: [Feasible]
- Efficient Burner Design: [Feasible]
- Good Combustion Practices: [Feasible]

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Efficient Burner Design	1	Base Case
O&M Practices	2	Base Case
Good Combustion Practice	3	Base Case

Step 4: Evaluate most effective controls and document results:

PSO has chosen to apply Efficient Burner Design, O&M Practices, and Good Combustion Practices for selecting a BACT limit. Therefore, no further evaluation under Step 4 is required.

Step 5: Select BACT:

PSO has chosen to apply Efficient Burner Design, O&M Practices, and Good Combustion Practices for selecting a BACT limit. PSO proposed and DEQ accepts a CO_{2e} BACT emission limit for all heaters of 117.1 lb/MMBtu.

Compliance with the BACT emission limits will be demonstrated by combusting pipeline-quality natural gas. Based on review of the RBL database, the proposed CO_{2e} BACT limit is consistent with established limits for comparable natural gas-fired heaters.

SECTION V.3 BACT ANALYSIS FOR SCCT SUSD OPERATIONS

Section V.1 contains the BACT analysis for SCCT regarding normal operations. PSO is proposing Startup and Shutdown (SUSD) operations as well.

SECTION V.3.1 NO_x BACT - SCCT SUSD OPERATIONS**Step 1: Identify all control technologies:**

Combustion control options include: Water or Steam Injection, DLN or DLE Combustion Technology, and Good Combustion Practices.

Post-combustion control options include: EM_xTM/SCONO_xTM Technology, SCR, SCR with Zero-SlipTM, SNCR, and METEORTM.

Each NO_x control technology is described in greater detail in Section V.1.1.

Step 2: Eliminate technically infeasible options:

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

- Water or Steam Injection: [Not Feasible]

The purpose of water/steam injection is to reduce the turbine's peak flame temperature, which occurs during normal operations, not SUSD. Therefore, it is eliminated as

technically infeasible for the control of NO_x during SUSD operations based on general engineering principles.

- DLN or DLE Combustion Technology: [Not Feasible]

DLN reduces NO_x by using lean mixtures of air-fuel, fuel staging, or decreasing the combustion residence time, all of which are infeasible during SUSD operations based on general engineering principles. As such, DLN is eliminated from further consideration as a NO_x control option during SUSD operations. (Note that DLN will be employed during normal operations).

- Good Combustion Practices: [Feasible]

Good combustion practices allow equipment to operate as efficiently as possible and maintain minimal emission releases during all modes of operation. This is considered technically feasible for SUSD operations.

- EM_xTM /SCONO_xTM Technology: [Not Feasible]

EM_xTM /SCONO_xTM catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_x, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_xTM /SCONO_xTM catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation. Additionally, the operating range of the catalyst is well below the exhaust temperature for simple-cycle combustion turbines. Consequently, EM_xTM /SCONO_xTM is not technically feasible for the proposed simple-cycle combustion turbines.

- SCR: [Not Feasible]

Combustion temperatures during SUSD are inherently lower than the optimal temperatures for the operation of SCR (480 °F to 800 °F), rendering SCR technically infeasible during SUSD operations.

- SCR with Zero-SlipTM: [Not Feasible]

Based on the review of available control technologies, to date, the Zero-SlipTM catalyst technology has not been demonstrated on large, utility-size units, with full scale operation demonstrated on a 7.5 MW Solar Taurus combustion turbine. In addition, this technology is essentially SCR with a focus on reducing ammonia slip. Accordingly, as this technology has not been demonstrated on large, utility size units, and it would not achieve NO_x emission rates lower than that achieved by conventional SCR designs, the ZeroSlipTM technology option is not considered a technically feasible control option.

- SNCR: [Not Feasible]

The temperature range required for effective operation of this technology, 1,600 °F to 2,000 °F, is far greater than the peak exhaust temperature for the proposed turbines. In addition, a review of the RBLC database and AP-42's supplemental database for Chapter 3.1, Stationary Gas Turbines, April 2000, shows that SNCR has not been demonstrated on turbine of the nature proposed by PSO. Given that the changes to adapt units for use of SNCR, such as adding a flue gas heater, are not practical and would reduce the energy efficiency of the generating units, SNCR is eliminated as a technically feasible option for control of NO_x emissions from the proposed turbines.

- METEORTM: [Not Feasible]

The METEORTM catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320-MW Siemens/Westinghouse 501G combustion turbine installed in November 2015. A review of the RBLC database for turbines similar to the proposed units did not return any units that use the METEORTM catalyst technology. As there is limited commercial operating experience with the METEORTM catalyst, the METEORTM technology option is not considered a technically feasible control option for purposes of BACT.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below:

Control Technology	Rank	Estimated Efficiency
Good Combustion Practice	1	Base Case

Step 4: Evaluate most effective controls and document results:

None of the control options are eliminated based on an evaluation of collateral impacts or cost analysis.

Step 5: Select BACT:

PSO proposed and DEQ accepts the use of good combustion practices and limiting the number of SUSD with limits as follows:

- Startup (uncontrolled): 58 lb/event, with each event lasting 18 min, and 300 events for each SCCT
- Shutdown: 32 lb/event, with each event lasting 13 min, and 300 events for each SCCT

PSO proposed the manufacturer's emission estimates for SUSD events as BACT. For the SCCTs, PSO will demonstrate compliance with the lb/event rates shown above using a CEMS.

SECTION V.3.2 CO BACT - SCCT SUSD**Step 1: Identify all control technologies:**

Candidate control options identified include the following: Catalytic Oxidation, EM_XTM/SCONO_XTM Technology, and Good Combustion Practices.

Each CO control technology is described in greater detail in Section V.1.2.

Step 2: Eliminate technically infeasible options:

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

- Catalytic Oxidation: [Not Feasible]

Combustion temperatures during SUSD are inherently lower than the optimal temperatures for the operation of oxidation catalyst (600 °F to 800 °F), rendering oxidation catalyst technically infeasible during SUSD operations.

- EM_XTM/SCONO_XTM Technology: [Not Feasible]

The EM_XTM/SCONO_XTM catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_x, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_XTM/SCONO_XTM catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation. Additionally, the operating range of the catalyst is 300 °F to 700 °F, well below the exhaust temperature for simple-cycle combustion turbines.⁵⁸ Consequently, it is concluded that EM_XTM/SCONO_XTM is not technically feasible for the proposed turbines.

- Good Combustion Practices: [Feasible]

This represents the base case for design and operation of the SCCTs during SUSD.

Step 3: Rank remaining control technologies by control effectiveness:

Of the control technologies available, technically feasible options are ranked below

Control Technology	Rank	Estimated Efficiency
Good Combustion Practice	1	Base Case

Step 4: Evaluate most effective controls and document results:

None of the control options are eliminated based on an evaluation of collateral impacts or cost analysis.

Step 5: Select BACT:

PSO proposed and DEQ accepts good combustion practices and limiting the number of SU/SD as BACT with the following limits:

- Startup (uncontrolled): 397 lb/event, with each event lasting 18 min, and 300 events for each SCCT
- Shutdown: 253 lb/event, with each event lasting 13 min, and 300 events for each SCCT

PSO will demonstrate compliance using CO CEMS.

SECTION VI. AMBIENT AIR IMPACTS ANALYSIS

As part of the PSD review for this application, PSO was required to complete air quality analyses for NO₂, CO, PM₁₀, PM_{2.5}, and ozone. The goal of the air quality analysis was to demonstrate that the project will not cause or contribute to a violation of any National Ambient Air Quality Standards (NAAQS) or PSD Increments. The relevant NAAQS and PSD Increments are summarized in the table below.

Pollutant	Averaging Period	NAAQS (µg/m ³)	PSD Increment (Class II) (µg/m ³)
NO ₂	1-hr	188	None
	Annual	100	25
CO	1-hr	40,000	None
	8-hr	10,000	None
PM ₁₀	24-hr	150	30
	Annual	None	17
PM _{2.5}	24-hr	35	9
	Annual	9	4
Ozone	8-hr	70-ppb	None

The Air Quality Analysis consisted of multiple, pollutant-specific analyses. The NO₂, CO, PM₁₀, PM_{2.5} analyses were completed using the American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD) modeling system, and the ozone analysis was completed using EPA's Tier 1 demonstration tool: Modeled Emission Rates for Precursors (MERPs). All analyses were prepared in accordance with the DEQ's "Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits" (June 2017).

SECTION VI.1 AERMOD SETUP

The latest version (v24142) of the AERMOD model (and related preprocessors) was used to predict the concentrations of NO₂, CO, PM₁₀, and primary PM_{2.5}. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and is the preferred model for use by industrial sources for this type of air quality analysis. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

The AERMOD modeling system is composed of three modular components: AERMAP (v24142), the terrain preprocessor; AERMET (v24142), the meteorological preprocessor; and AERMOD, the control module and modeling processor. AERMAP is used to import terrain elevations for selected model objects and to generate the receptor hill height scale data that are used by AERMOD to drive advanced terrain processing algorithms. AERMET generates a separate surface file and vertical profile file to pass meteorological observations and turbulence parameters to AERMOD. AERMET meteorological data are refined for a particular analysis based on the choice of micrometeorological parameters that are linked to the land use and land cover around the facility and/or meteorological site

Terrain Data

Following DEQ guidance, modeling with elevated terrain was used for this analysis. AERMAP was used to determine stack, building, and receptor elevations/hill heights based on U.S. Geological Survey (USGS) digital elevation data. Elevations entered into the model were obtained using the National Elevation Dataset (NED), the primary elevation data product of USGS.

Meteorological Data

Pre-processed meteorological data obtained from the DEQ was used for the modeling analysis. Integrated Surface Hourly (ISH) meteorological data from the Tulsa International Airport (KTUL) was provided for years 2011 through 2015 as well as upper air data from the Norman/Max Westheimer Airport (OUN).

Building Downwash

Building wake effects on each emission point source were incorporated using BPIP-PRIME (v04274). BPIP-PRIME calculates all direction specific building data required by the air dispersion model to enable it to include the appropriate building downwash algorithm in the calculations. The structure dimensions are then imported into AERMOD on an emission point-specific basis.

Receptors

For Class II Area Receptors, ground-level concentrations were calculated by AERMOD at receptor locations placed according to DEQ's current guidance, which calls for fence line receptors and five Cartesian grids covering a region that extends at least 10 kilometers (km) from all facility emission sources. The spacing and extents of the fence line receptors and the Cartesian grids are summarized below:

- Fence line receptors placed 100 meters (m) apart along the facility fence line.
- 100-m grid, extending approximately 1.0 km from the fence line, exclusive of the fence line grid.

- 250-m grid, extending approximately 2.5 km from the fence line, exclusive of the 100-meter grid.
- 500-m grid, extending approximately 5.0 km from the fence line, exclusive of the 250-meter grid.
- 750-m grid, extending approximately 7.5 km from the fence line, exclusive of the 500-meter grid.
- 1,000-m grid, extending approximately 10 km from the fence line, exclusive of the 750-meter grid.

For the Class I PSD Increment analysis, the ground level concentrations were calculated at receptors placed in a ring at a 50 km distance from the Northeastern Power Plant in the direction of the nearby Class I Areas. Class I Areas within 300 km of the Northeastern Power Plant are Caney Creek Wilderness Area (268 km) and Upper Buffalo Wilderness Area (210 km). The receptor grid used in this analysis reflects DEQ's current guidance that receptors be placed every 10 km along the 50 km radius along the direction of the Class I Areas.

NO_x to NO₂ Modeling Approach

The Plume Volume Molar Ratio Method (PVMRM) was utilized for all NO₂ modeling assessments. It was implemented based on all regulatory default options per DEQ's and EPA's modeling guidance.

SECTION VI.2 MERPS ANALYSIS

Ozone

Between 2018 and 2024, EPA issued several guidance documents providing frameworks for air agencies and permit applicants to satisfy compliance demonstration requirements for ozone under the PSD program. The guidance suggests a two-tier approach for addressing single source impacts. The first tier involves the use of relationships between precursor emissions and ambient ozone impacts developed from EPA's modeling of hypothetical sources.

The ratio between the modeled ozone air quality impact from the hypothetical source ($\mu\text{g}/\text{m}^3$ or ppb) and the annual NO_x modeled emission rate from hypothetical source are multiplied by the NO_x annual emission rate for the project to determine the ozone contribution from NO_x. Similarly, the ratio between the modeled ozone air quality impact from the hypothetical source ($\mu\text{g}/\text{m}^3$ or ppb) and the annual VOC modeled emission rate from hypothetical source are multiplied by the VOC annual emission rate for the project to determine the ozone contribution from VOC. The ozone contribution from VOC is added to the ozone concentration from NO_x to determine the total ozone concentration.

The relationship between precursor emissions and ozone is determined from the nearest hypothetical source as determined from U.S. EPA's MERPS View Qlik. For the proposed project, the hypothetical source located in Muskogee, OK closely matches the project site. For both the NO_x and VOC comparison, the 500 TPY emission rate, 10-meter-high hypothetical source was used. The proposed units will have stack heights of 131 feet, and the 10-m stack height is the only hypothetical height available for both pollutants at the 500 TPY emission rate.

Secondary PM_{2.5}

The relationship between precursor emissions and secondary PM_{2.5} was determined from a hypothetical source in Muskogee County, similar to the hypothetical source that was used for ozone. The 500 ton/year emission rate, 10-meter-high hypothetical source was used for NO_x and SO₂. The ratio between the modeled PM_{2.5} air quality impact from the hypothetical source (µg/m³ or ppb) and the NO_x modeled emission rate from hypothetical source (TPY) was multiplied by the NO_x annual emission rate for the project to determine the PM_{2.5} contribution from NO_x. Similarly, the ratio between the modeled PM_{2.5} air quality impact from the hypothetical source (µg/m³ or ppb) and the SO₂ modeled emission rate from hypothetical source (TPY) was multiplied by the SO₂ annual emission rate for the project to determine the PM_{2.5} contribution from SO₂. The secondary PM_{2.5} contribution from NO_x was added to the secondary PM_{2.5} concentration from SO₂ to determine the total secondary PM_{2.5} concentration.

The secondary PM_{2.5} impacts were added to the primary PM_{2.5} impacts determined using AERMOD to calculate the total PM_{2.5} impacts.

SECTION VI.3 OVERVIEW OF PSD CLASS II AREA AIR QUALITY ANALYSES

The purpose of the PSD air quality analyses is to demonstrate that the emissions from the project will not cause or contribute to a violation of the NAAQS or Class II PSD Increments. The following steps were taken to make this demonstration.

Step 1A – Project Significance Analyses

First, a “Project Significance Analysis” was conducted for all pollutants for which the project’s net emissions increases exceed the PSD SERs to determine if the emissions associated with the proposed project could cause a significant impact on the area surrounding the facility. For the Project Significance Analysis, only new and modified sources were considered. For this application, these include the following:

- Two 229-MW SCCTs equipped with DLN.
- Two 2.5-MMBtu/hr fuel gas heaters.

A significant impact is a modeled impact that exceeds the applicable significant impact level (SIL). The relevant SILs are summarized in the table below. In addition to the number value of the SIL, the table also shows the specific statistical form that is relevant in evaluating modeled concentrations against the SILs.

Pollutant	Averaging Period	Class I SIL (µg/m ³)	Class II SIL (µg/m ³)	Form of the SIL
NO ₂	1-hr	None	7.5	Max of the 5-year average of the 1 st high
	Annual	0.1	1.0	Max annual average, considering 5 years

Pollutant	Averaging Period	Class I SIL ($\mu\text{g}/\text{m}^3$)	Class II SIL ($\mu\text{g}/\text{m}^3$)	Form of the SIL
SO ₂	1-hr	None	7.8	Max of the 5-year average of the 1 st high
	3-hr	1	25	Max of 1 st high, considering 5 years
	24-hr	0.2	5	Max of 1 st high, considering 5 years
	Annual	0.1	1	Max annual average, considering 5 years
CO	1-hr	None	2,000	Max of the 1 st high, considering 5 years
	8-hr	None	500	Max of the 1 st high, considering 5 years
PM ₁₀	24-hr	0.32	5	Max of the 1 st high, considering 5 years
	Annual	0.20	1	Max annual average, considering 5 years
PM _{2.5}	24-hr	0.27	1.2	Max of the 5-year average of the 1 st high
	Annual	0.03	1.3	Max annual average, considering 5 years
Ozone	8-hr	None	1-ppb	None – based on EPA’s hypothetical modeling to establish MERPS

If the concentration of a pollutant resulting from the Project Significance Analysis is less than the SIL, then further analyses are not required for that pollutant. If the concentration is greater than the SIL, then a cumulative analysis is required.

Step 1B – Ambient Monitoring Requirements

In addition to determining whether cumulative modeling is required, the Project Significance Analysis is also used to determine whether an applicant is exempt from ambient monitoring requirements. To determine whether pre-construction monitoring should be considered, the Project Significance Analysis results are assessed against Significant Monitoring Concentrations (SMCs). The applicable SMC for each relevant pollutant and averaging period is shown in the table below:

Pollutant	Averaging Period	Significant Monitoring Concentration ($\mu\text{g}/\text{m}^3$)
NO ₂	Annual	14
CO	8-hr	575
PM ₁₀	24-hr	10
PM _{2.5}	24-hr	No minimum (i.e. 0)
Ozone	8-hr	VOC or NO _x emissions increase > 100 TPY

Because there is no SMC for PM_{2.5} (i.e., the SMC for PM_{2.5} is 0 $\mu\text{g}/\text{m}^3$), preconstruction ambient monitoring for PM_{2.5} must be addressed. Ambient monitoring of ozone must also be addressed.

Per EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), if existing data from ambient monitoring stations operated by Federal, state, or local agencies are representative of the concentrations expected to occur in the area surrounding the plant site, this data may be used to fulfill the preconstruction monitoring requirements. An analysis of nearby PM_{2.5} and ozone monitors demonstrates that existing data is representative. Therefore, DEQ can waive the requirement to conduct preconstruction monitoring for PM_{2.5} and ozone.

The Tulsa Central PM_{2.5} monitor (ID 40-143-1127) is expected to be a conservative representation of the project area. The 2021-2023 design values from this monitor are 8.6 µg/m³ for the annual standard and 20 µg/m³ for the 24-hour standard.

The Mannford ozone monitor (Site ID 40-037-0144) provides a representative estimate of the ozone concentrations in the area surrounding the power plant due to its proximity, availability of complete ozone monitoring data for three recent calendar years, and similarity of the emissions profile and surrounding air shed in the region of the monitoring station and the power plant. Note that the hourly data from this monitor was used as an input for the NO₂ modeling.

Step 2A – Cumulative Analysis: NAAQS

NAAQS are the maximum concentration ceilings, measured in terms of total concentration of a pollutant in the atmosphere, which define the “levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health” and that “protect the public welfare from any known or anticipated adverse effects of a pollutant.” The table below includes a summary of the relevant NAAQS, which are codified under 40 CFR 50. The table also shows the specific statistical form for demonstrating compliance with that NAAQS; that statistical form is relevant in evaluating modeled concentrations.

Pollutant	Averaging Period	Primary and Secondary NAAQS (µg/m³)	Form of the NAAQS
NO ₂	1-hr	188	The 5-year average of the 98th percentile of the daily maximum 1-hr average (highest eighth high modeled output)
	Annual	100	Annual arithmetic average (highest first high modeled output)
CO	1-hr	40,000	Not to be exceeded more than once per calendar year
	8-hr	10,000	Not to be exceeded more than once per calendar year
PM ₁₀	24-hr	150	Not to be exceeded more than five (5) times in five (5) consecutive years (highest sixth high modeled output)
	Annual	-	EPA Revoked on December 18, 2006
PM _{2.5}	24-hr	35	The 5-year average of the 98th percentile 24-hr average concentration (highest eighth high modeled output)

Pollutant	Averaging Period	Primary and Secondary NAAQS ($\mu\text{g}/\text{m}^3$)	Form of the NAAQS
	Annual	17	The 5-year average of the annual arithmetic average concentration (highest first high modeled output)
Ozone	8-hr	70-ppb	None

NAAQS analyses consider the total future air quality by evaluating the existing levels of air quality (i.e., background concentrations and existing sources of emissions) together with the increase in air concentrations attributable to the proposed project.

Background concentrations are relied upon to represent air quality concentrations attributable to sources that are not explicitly modeled (e.g., mobile sources, small but local stationary sources, non-regulated fugitive sources, and large but distant sources). As shown in Section V.5 “Modeling Results” below, a NAAQS analysis is only required for the 1-hr NO_2 standard.

There are three NO_2 monitors in Oklahoma: two in Oklahoma City, one in Tulsa. The monitor in Tulsa is approximately three miles north of downtown Tulsa, which is not representative of the area surrounding the facility. Of the two monitors in Oklahoma City, which also renders it as a poor representation, one is a near-road monitor while the other, OKC North, is in a more suburban environment that more closely matches the activities in the area surrounding the facility. However, because the Oklahoma City monitor is located approximately 180 km from the facility, compared to a distance of 30 km from the Tulsa monitor, DEQ prefers the use of the Tulsa Central monitor (ID 40-143-1127) as the representative background monitor. Based on the 2022-2024 design values from that monitor, a 1-hr NO_2 background concentration of $29.5 \mu\text{g}/\text{m}^3$ was used.

Step 2B – Cumulative Analysis: PSD Increment

As shown in Section VI.5 “Modeling Results” below, a cumulative analysis is only required for 1-hr NO_2 . Since there are no Increment thresholds established for 1-hr NO_2 , a PSD Increment analysis is not necessary.

SECTION VI.4 REPRESENTATION OF EMISSION SOURCES

This section provides a detailed description of the AERMOD source inputs for the proposed equipment, the existing Northeastern equipment (for the NAAQS analysis), and the inventory of nearby sources (for the NAAQS analysis).

The hourly emissions obtained from Section X are used as the basis for the modeled emissions. In addition to providing the emissions data, the technology vendor (GE) also provided the exhaust temperature and flow rate for each operating load and various ambient conditions, and these data were used in the modeling. The following table shows the model inputs for the proposed sources.

Parameter	TURB_1 Data	TURB_2 Data	FDP_1 Data	FDP_2 Data
Description	CT Exhaust Stack	CT Exhaust Stack	Fired Dewpoint Heater and Inlet Scrubber	Fired Dewpoint Heater and Inlet Scrubber
Northing, meters	257,974.6	257,975.6	257,894	257,894
Easting, meters	4,034,801.8	4,034,853.8	4,034,972.6	4,034,965.1
Elevation, meters	195.11	194.63	194.79	194.72
NO ₂ , lb/hr	127.62	127.62	0.028	0.028
CO, lb/hr	666.64	666.64	0.19	0.19
PM ₁₀ , lb/hr	7.08	7.08	0.03	0.03
PM _{2.5} , lb/hr	7.08	7.08	0.03	0.03
Stack height, ft	131.23	131.23	30.0	30.0
Stack Temp, °F	1,130	1,130	250	250
Stack Velocity, m/s	23.19	23.19	116.43	116.43
Stack Diameter, ft	22.0	22.0	0.167	0.167

For the 1-hr NO₂ NAAQS analysis, the following existing emission sources at Northeastern were included: Unit 1A, Unit 1B, Unit 2, Unit 3, Auxiliary Boiler 2, and Auxiliary Boiler 3.

Modeled emission rates were based on each unit's potential to emit.

Note that EPA's guidance for implementation of the 1-hr NO₂ NAAQS under PSD advises that emergency units are not to be modeled because the emissions will not occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hr concentrations. Based on this guidance, the existing emergency engines at Northeastern were not included in the NAAQS modeling.

DEQ provided a list of preliminary data for all the regional sources including emissions and source parameters to be included in the full impact analysis. Regional sources were evaluated and developed based on considerations EPA's Guidance on Developing Background Concentrations for Use in Modeling Demonstrations (11/24).

SECTION VI.5 MODELING RESULTS

The following tables provide the modeled results from the Class I and Class II Project Significance Analyses. As shown in the tables, no pollutants or averaging periods are significant for the Class I analysis and will not require increment modeling. Modeled impacts for NO₂ annual, CO 1-hour and 8-hour, PM_{2.5} 24-hour and annual, PM₁₀ 24-hour and annual, and ozone 8-hour averaging periods are not significant Class II analysis; therefore, no cumulative analyses are required for these pollutants and averaging periods. A cumulative NAAQS analysis will only be required for the NO₂ 1-hour analysis.

Class I Project Significance Analyses Results for NO₂

Met Data Year	Averaging Period	Model Concentration (µg/m³)	SIL (µg/m³)	Is the Modeled Concentration > SIL?
2011	Annual	0.020	0.1	No
2012	Annual	0.015	0.1	No
2013	Annual	0.022	0.1	No
2014	Annual	0.020	0.1	No
2015	Annual	0.011	0.1	No

Class I Project Significance Analyses Results for PM₁₀

Met Data Year	Averaging Period	Model Concentration (µg/m³)	SIL (µg/m³)	Is the Modeled Concentration > SIL?
2011	Annual	0.001	0.3	No
2012	Annual	0.001	0.3	No
2013	Annual	0.002	0.3	No
2014	Annual	0.001	0.3	No
2015	Annual	0.001	0.2	No
2011-2015	24-hr	0.018	0.3	No

Class I Project Significance Analyses Results for PM_{2.5}

Met Data Year	Averaging Period	Model Concentration (µg/m³)	SIL (µg/m³)	Is the Modeled Concentration > SIL?
2011	Annual	0.005	0.27	No
2012	Annual	0.005	0.27	No
2013	Annual	0.006	0.27	No
2014	Annual	0.005	0.27	No
2015	Annual	0.005	0.03	No
2011-2015	24-hr	0.092	1.2	No

Class II Project Significance Analyses Results for NO₂

Met Data Year	Averaging Period	Model Concentration (µg/m³)	SIL (µg/m³)	Is the Modeled Concentration > SIL?
2011	Annual	0.184	1.0	No
2012	Annual	0.177	1.0	No
2013	Annual	0.169	1.0	No
2014	Annual	0.257	1.0	No
2015	Annual	0.151	1.0	No
2011-2015	1-hr	10.739	7.5	Yes

Class II Project Significance Analyses Results for CO

Met Data Year	Averaging Period	Model Concentration ($\mu\text{g}/\text{m}^3$)	SIL ($\mu\text{g}/\text{m}^3$)	Is the Modeled Concentration > SIL?
2011	1-hr	74.156	2,000	No
	8-hr	29.845	500	No
2012	1-hr	81.997	2,000	No
	8-hr	29.504	500	No
2013	1-hr	91.480	2,000	No
	8-hr	23.313	500	No
2014	1-hr	82.095	2,000	No
	8-hr	44.236	500	No
2015	1-hr	79.055	2,000	No
	8-hr	54.531	500	No

Class II Project Significance Analyses Results for PM₁₀

Met Data Year	Averaging Period	Model Concentration ($\mu\text{g}/\text{m}^3$)	SIL ($\mu\text{g}/\text{m}^3$)	Is the Modeled Concentration > SIL?
2011	Annual	0.034	1.0	No
2012	Annual	0.035	1.0	No
2013	Annual	0.031	1.0	No
2014	Annual	0.034	1.0	No
2015	Annual	0.026	1.0	No
2011-2015	24-hr	0.298	5.0	No

Class II Project Significance Analyses Results for PM_{2.5}

Met Data Year	Averaging Period	Model Concentration ($\mu\text{g}/\text{m}^3$)	SIL ($\mu\text{g}/\text{m}^3$)	Is the Modeled Concentration > SIL?
2011	Annual	0.038	0.13	No
2012	Annual	0.039	0.13	No
2013	Annual	0.035	0.13	No
2014	Annual	0.038	0.13	No
2015	Annual	0.030	0.13	No
2011-2015	24-hr	0.265	1.2	No

Class II Project Significant Analyses Results for Ozone

County	Pollutant	Emission Rate (TPY)	Stack Height (meters)	Modeled Impact (ppb)	Project Increase (TPY)	Ozone Impact (ppb)
Muskogee	NO _x	500	10	1.459272	243.94	0.7119
	VOC	500	10	0.144026	30.02	0.0086
Total						0.7206

Project Significant Analyses for Secondary PM_{2.5}

County	Pollutant	Averaging Period	Emission Rate (TPY)	Stack Height (meters)	Modeled Impact (µg/m³)	PM2.5 MERP (µg/m³)	PM2.5 Impact (µg/m³)
Muskogee	NO _x	24-hour	500	10	0.1151	5,212.312	0.0562
	SO ₂		500	10	1.1887	504.765	0.0219
	NO _x	Annual	500	10	0.0076	8,539.002	0.0037
	SO ₂		500	10	0.0133	4,883.008	0.0002
Total 24-hour							0.0781
Total Annual							0.0040

As shown above, modeled impacts from the proposed sources for all pollutants and averaging periods are less than the respective SILs except for the Class II NO₂ 1-hour analysis. As such, a cumulative NAAQS analysis is required for NO₂ 1-hour.

A cumulative NAAQS analysis was required for the NO₂ 1-hour averaging period based on the results of the Project Significance Analysis. As shown in the table below, modeled impacts were added to a representative background concentration of 29.5 ppb, which is 55.47 µg/m³, and the combined impacts are less than the NAAQS.

Averaging Period	Model Concentration (µg/m ³)	Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)
2011-2015	72.37	55.47	127.84	188

SECTION VI.6 CLASS I AREA AIR QUALITY RELATED VALUES ANALYSIS

One of the purposes of the PSD program is “to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value.” Under the PSD provisions, Congress established a land classification scheme for these areas of the country (Class I), specifically including: international parks; national wilderness areas which exceed 5,000 acres in size; national memorial parks which exceed 5,000 acres in size; and national parks which exceed 6,000 acres in size.

In October 2010, the Federal Land Managers’ Air Quality Related Values (AQRV) Workgroup (FLAG) Phase I Report – Revised (FLAG 2010) set a threshold ratio of emissions to distance, below which an AQRV review is not required for sources located greater than 50 km from any Class I area. Specifically, if:

$$Q \text{ (TPY)} / d \text{ (km)} < 10, \text{ then no AQRV analysis is required}$$

Q is the combined emissions increase of SO₂, NO_x, PM₁₀, and H₂SO₄ in tons per year (TPY) based on 24-hour maximum allowable emissions (which are annualized) and D is the nearest distance to a Class I area in kilometers (km).

For Northeastern, Upper Buffalo Wilderness Area is the nearest Class I area, and d is 211 km. Q is 9.18 TPY of SO₂ + 241.74 TPY of NO_x + 20.30 TPY of PM₁₀ + 2.12 TPY of H₂SO₄ for a total of 273.34 TPY. Therefore, Q/d is 1.3, and a Class I area AQRV review is not required as part of this application.

SECTION VI.7 ADDITIONAL IMPACTS ANALYSIS

Per 40 CFR §52.21(o), all PSD applications must include an Additional Impacts Analysis consisting of: (1) growth impacts, (2) soils and vegetation impacts, and (3) visibility impairment. Each of these analyses is summarized below.

Growth Analysis

The purpose of the growth analysis is to predict quantitatively the amount of new growth likely to occur to support the source or modification under review and to estimate the emissions that will result from the associated growth. First, an assessment is made regarding the amount of residential growth the modified source will bring to the area. This depends on the size of the available work force, the number of new employees, and the availability of housing in the area. Associated commercial and industrial growth consists of new sources providing goods and services to the new employees and to the modified source itself. Once these anticipated growth effects have been considered, an estimate of the air pollutant emissions that would likely result from the associated growth is made.

The project is not expected to result in any net additional labor on a permanent basis. Furthermore, no major secondary industry growth will result from the proposed project. Thus, any air quality impact resulting from industrial, commercial, and residential growth in the local area due to the proposed project will be negligible.

Soil and Vegetation Analysis

The secondary NAAQS were established at concentration levels below which no harmful effects to either soil or vegetation are expected. As demonstrated in this application, the proposed project will have no adverse impact on the NAAQS. Thus, it can be concluded that any impact on soil and vegetation will be negligible.

Visibility Analysis

EPA prescribes the use of its Workbook for Plume Visual Impact Screening and Analysis for conducting a visibility impairment analysis. Three levels of screening procedures are outlined by EPA. If the criteria for the first (most conservative) screening level are met, no further analysis is required. The VISCREEN model is recommended for the first level (Level 1) screen. If calculated values from the VISCREEN model are greater than the standardized screening values, the emissions are considered to potentially impair visibility. If the potential for visibility impairment is indicated, the next level analysis, Level 2 analysis, is required. The VISCREEN model primarily considers NO₂ and PM emissions increases associated with a modification (VISCREEN does not consider or calculate visibility impacts due to ozone). For this application, VISCREEN was executed based on the emissions increases for NO_x and PM₁₀. As evident from the VISCREEN analysis, the proposed project's emissions will not cause visibility impairment.

SECTION VII. PROCESS DESCRIPTION

By the year 2000, Unit 1 had been “repowered.” The boiler powering the steam turbine was replaced by two-160 MWe combined cycle gas turbines with heat recovery steam generators (HRSGs). Steam generated by the heat from the turbines and HRSGs re-powers the Unit 1 steam turbine, which was not removed when the original boiler was retired. The gas turbines (combustion turbines or CTs) are not capable of simple cycle operations.

The Unit 2 boiler is 100% gas-fueled. Permit No. 2003-410-C (M-6) PSD authorized the modification for installation of low-NO_x burners and overfire air (LNB/OFA) on Unit 2.

The boiler providing steam for Unit 3 will only be fueled by natural gas after the project. The Applicant has added low-NO_x concentric firing systems (LNCFS, which is a trademark for the proposed system) consisting of low-NO_x burners (LNB) and separated overfire air (SOFA) to Unit 3 in advance of EPA’s Regional Haze requirements, under the modification authorized in Permit No. 2003-410-TVR (M-3), issued March 8, 2012. That project was a major modification, and applicant had refined the system by “Refined Tuning” under Permit No. 2003-410-C (M-6) PSD, and performance testing has verified compliance with the NO_x and CO emission limits.

The pollution control project covered by Permit No. 2003-410-TVR (M-5) which authorized the addition of two injection systems to control emissions of mercury, SO₂ and acid gases, as well as a baghouse that serves as the only control device for existing PM emissions. The previous PM control device for Unit 3 - the Electrostatic Precipitator, which is upstream of the equipment added under Permit No. 2003-410-TVR (M-5), began serving only as the product recovery device, as of April 16, 2016. Unit #4 was retired in place as of April 16, 2016.

Two additional boilers serve as natural gas-fired auxiliary steam generators, one serving Unit 2 (Auxboiler 1/2, now Auxboiler 2), and another originally serving Unit 3 (Auxboiler 3). Beginning April 16, 2016, Auxboiler 3 began serving Unit 3 only. Although applicant uses the designation “Unit” to refer to the entire generating unit, including the boiler and all appurtenances, the turbine/generator, connecting piping and all controls, this Memorandum will frequently mean only the boiler and appurtenances when using the term “Unit”. The meaning of the term must be interpreted in context.

Along with these units, two additional simple cycle combustion turbines and their associated heaters will be constructed at the facility and expected to begin operations in January 2027.

SECTION VIII. PERMIT HISTORY

This table lists the permit history for the facility from issuance of the initial Title V permit.

Permits	Date Issued	Description
75-010-C	7/17/1975	Initial Construction Permit to install a coal-fired steam turbine generating unit.
75-010-O	12/28/1981	Operating Permit following construction authorization Permit No. 75-010-C.

Permits	Date Issued	Description
75-010-AD (M-1)	9/6/1996	Applicability Determination for establishing if installation of an Energy Management System (EMS) and opacity monitors for the electrostatic precipitator would require an Air Quality permit.
96-476-C	2/21/1997	Construction Permit to replace auxiliary boilers (Unit 1 and 2) with an existing auxiliary boiler being relocated from PSO's Riverside Station. The existing equipment was unpermitted based on policies in effect at the time of construction in 1968 for the Riverside boiler, 1961 Unit 1, and 1970 Unit 2.
96-476-O	7/21/1997	Operating Permit following construction authorization Permit No. 96-476-C.
96-288-AR (M-1)	1/6/1998	Initial Acid Rain Permit.
96-288-TV	6/30/1999	Initial Title V Operating Permit.
96-288-C PSD	10/18/1999	Initial Title V Construction Permit following the discontinued use of the boiler at Unit 1 and the construction of two, 160-MW combustion turbines with heat recovery steam generators that will repower the steam turbine at existing Unit 1.
96-288-TV (M-1)	9/29/2000	Modification to request for increase emissions limits for hydrogen fluoride. Along with the addition of emission limits for barium, benzyl chloride, and pentane.
2004-196-ARR	12/13/2004	Acid Rain Renewal Permit.
2003-410-TVR	2/4/2008	Title V renewal, no changes were requested
2009-470-ARR2	5/3/2010	Acid Rain Renewal Permit.
2003-410-TVR (M-2)	8/19/2010	Administrative amendment to correct anniversary date of their Title V permit to correspond with the original (Permit No. 96-288-TV).
2003-410-TVR (M-3)	3/8/2012	Modification to add low-NO _x concentric firing separated overfire air systems to the coal-fired Units 3 and 4.
2003-410-C (M-4) PSD	7/16/2013	Modification to tune the separated overfire air system.
2003-410-C (M-6) PSD	7/23/2013	Administrative amendment to correct errors in Permit No. 2003-410-C (M-4) PSD. An older draft was inadvertently used.
98-228-TV (M-3)	7/23/2013	Modification to incorporated BART analysis and requirements.
2003-410-TVR (M-5)	11/20/2013	Modification to add an emission control project for Unit 3. The project is designed to comply with 40 CFR Part 63 Subpart UUUUU.
2012-918-TVR2	11/18/2014	Title V renewal, no changes were requested
2014-1749-ARR3	5/7/2015	Acid Rain Renewal Permit.

Permits	Date Issued	Description
2012-918-TVR2 (M-1)	8/17/2016	Modification to remove Unit 4, EUG 4, and EUG 10. Additionally, certain specific conditions were updated or removed.
2012-918-TVR2 (M-2)	8/10/2017	Modification to change/remove some of the PM emission limits.
2019-0782-ARR4	1/13/2020	Acid Rain Renewal Permit.
2019-0607-TVR3	8/24/2022	Title V renewal, no changes were requested
2024-0454-ARR5	3/4/2025	Acid Rain Renewal Permit.
2019-0607-C (M-1)	3/9/2026	Modification to incorporate the provisions of the Second Amended Regional Haze Agreement (SARHA) for Unit 2 and 3, including Unit 2's burner replacement. Additionally, certain specific conditions and equipment were updated or removed.
2019-0607-C (M-2)	In Review	Modification to replace Auxiliary Boiler 3 with a new, low NO _x burner. The rating of 239 MMBTUH will not change.
2019-0607-C (M-3) PSD	In Review	Modification to install two, 229-MW combustion turbines (Unit 5 and Unit 6) and their associated 2.5 MMBTUH gas heaters.
2019-0607-C (M-4)	In Review	Modification to replace Auxiliary Boiler 1/2 with a 276.5 MMBTUH Auxiliary Boiler. Now named Auxiliary Boiler 2

SECTION IX. EQUIPMENT

The emissions sources have been organized into Emissions Unit Groups (EUGs) identified below.

EUG-01 Gas Turbines and Heat Recovery Steam Generators (HRSG)

ID# ⁽¹⁾	Description	Serial No.	Rating (MW)	Rating (MMBTUH)	Construction Date
1A	GE MS7001FA	297510	160	1,684 ⁽²⁾	2000
1B	GE MS7001FA	297511	160	1,684 ⁽²⁾	2000

⁽¹⁾ Each turbine exhausts to a 99 MMBTUH Nooter-Erikson HRSG (duct burner). Steam generated by turbine hot exhaust, with additional heat from the HRSG, drives the old steam turbine.

⁽²⁾ Under certain operating conditions, the heat input of each turbine may be increased to 1,903 MMBTUH.

EUG-02 Grandfathered Steam Generators

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
2	Babcock and Wilcox UP-60	495	4,754	1970

EUG-03 Steam Generator

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
3	Combustion Engineering #4974 SCRR	490	4,775	1974/2015 ⁽¹⁾

⁽¹⁾ Low-NO_x concentric firing systems were installed in 2015. This is just for informational purposes only and does not trigger/constitute any permit condition.

EUG-Aux 2 Steam Generator

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
Aux 2	Babcock and Wilcox FM 120-136 I.H.	-	276.5	July 2026

EUG-Aux 3 Steam Generator

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
Aux 3	Combustion Engineering #3M1004	-	239	1974

EUG-16 Emergency Engines

ID#	Description	Fuel Type	Function	Rating (HP)	Construction Date
GEN 1/2	General Motors, Model MP45A (Electro-Motive Division MU-Type Power Plant)	Diesel	Service at Units 1 and 2	3,600	1968
GEN 3	Detroit Diesel Allison, Model 16V-149T (Supplied by United Engines, Inc., descriptor B/M 6571/6572 M-22C)	Diesel	Service at Unit 3	1,476	1979

EUG-Chem Store Stored Chemicals

Material	CAS #	Quantity (lb)	Use
Hydrogen	-	689	Generator heat-exchanger control
Aqueous Ammonia	1336-21-6	1,494	Control of boiler water pH

EUG-Insignificant Sources

Northeastern Station identifies various pieces of equipment as fitting the insignificant definition. These include nine (9) hydrocarbon storage tanks, a gasoline pump and storage tank, and a fly ash landfill (capped and closed as it is no longer active following the cessation of coal combustion in Unit 3).

EUG-20 SCCT

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
SCCT 5	GE Vernova	229	2,289.6	1/1/2027
SCCT 6	GE Vernova	229	2,289.6	1/1/2027

EUG-21 HTR

ID#	Description	Rating (MMBTUH)	Construction Date
HTR 1	Fuel Gas Heater	2.5	1/1/2027
HTR 1	Fuel Gas Heater	2.5	1/1/2027

EUG-22 Facility-Wide

This EUG is established to cover all rules or regulations that apply to the facility as a whole.

SECTION X. EMISSIONS**EUG-01: Emissions Gas Turbines and HRSG**

Emission factors for turbines 1A and 1B are based on manufacturers' guarantees. To assure conservatively high results, pound per hour figures were taken at -8°F (1,903 MMBTUH), while TPY data were taken at average ambient temperatures (1,684 MMBTUH). Note that the NO_x and CO values for the turbines are based on ppmv dry at 15% O₂ and SO₂ and H₂SO₄ hourly emissions are based on average ambient temperatures (1,684 MMBTUH). Emission factors for the duct burners at this facility are assumed to be similar to those guaranteed by the manufacturer at other GE Frame 7 installations with a rating of 99 MMBTUH. The factor for sulfuric acid fume emissions is found in AP-42 (9/98) Section 1.3.3.2. Although this part of AP-42 deals with liquid fuels, the discussion makes clear that the formation of acid mist is a function of SO₂ availability and is not a function of burner design or fuel. Worst case assumptions for acid mist and for SO₂ formation include an average annual and hourly content of 0.25 gr/100 dscf, along with an average formation rate of acid mist at 3% annually and 5% hourly. Gas heating value is taken to be 1,015 BTU/CF. Emissions calculated for EUG-01 turbines and HRSGs are valid for all operating scenarios.

Turbine and HRSGs/Duct Burners Emissions (per turbine and per duct burner)

Pollutant	Turbine Emission Factors	Turbine		Duct Burner Emission Factors	Duct Burner		2 Turbine Totals	
		lb/hr	TPY		lb/hr	TPY	lb/hr	TPY
NO _x	0.0567 lb/MMBTU ⁽¹⁾	108	418.0	0.09- lb/MMBTU	8.91	39.0	234.0	914.0
SO ₂	0.2 ppmv in the fuel	1.18	5.19	0.0142- lb/MMBTU	1.41	0.31	5.18	11.0
PM _{10/2.5}	0.011- lb/MMBTU	20.9	81.1	0.01- lb/MMBTU	0.99	4.34	43.78	171
VOC	0.1 ppmdv ⁽²⁾	0.40	1.49	0.001- lb/MMBTU	0.10	0.43	1.0	3.84
CO	0.0270- lb/MMBTU	51.7	198.0	0.09- lb/MMBTU	8.91	39.0	121.0	474.0
H ₂ SO ₄	0.000032- lb/MMBTU	0.06	0.24	0.0011- lb/MMBTU	0.11	0.48	0.34	1.44

⁽¹⁾ Includes a 1.03 ISO correction factor.

- (2) The VOC calculations provided by the manufacture's data are based on methane but should be based on VOC as emitted or propane. This error will need to be corrected in the next Title V Renewal review.

Emissions of HAP for EUG-01 are based on AP-42 (4/00) Table 3.1-3 with a rate of 1,684 MMBTUH (based on 1,020 BTU/SCF) for each combustion turbine.

EUG-01 HAP Emissions

Pollutant	Factors	Unit 1A		Unit 1B	
	lb/MMBtu	lb/hr	TPY	lb/hr	TPY
1,3-Butadiene	4.3E-07	0.001	0.004	0.001	0.004
Acetaldehyde	4.0E-05	0.080	0.352	0.080	0.352
Acrolein	6.4E-06	0.013	0.056	0.013	0.056
Benzene	1.2E-05	0.024	0.106	0.024	0.106
Ethylbenzene	3.2E-05	0.064	0.282	0.064	0.282
Formaldehyde	7.1E-04	1.428	6.254	1.428	6.254
Naphthalene	1.3E-06	0.003	0.011	0.003	0.011
PAH	2.2E-06	0.004	0.019	0.004	0.019
Propylene Oxide	2.9E-05	0.058	0.255	0.058	0.255
Toluene	1.3E-04	0.261	1.145	0.261	1.145
Xylenes	6.4E-05	0.129	0.564	0.129	0.564
Totals		2.07	9.05	2.07	9.05

EUG-01 Total Emissions

Point Source	NO _x		SO ₂		PM _{10/2.5}		VOC		CO	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1A	117.0	457.0	0.63	5.5	21.9	85.5	0.50	1.92	60.5	176.0
1B	117.0	457.0	0.63	5.5	21.9	85.5	0.50	1.92	60.5	176.0
Totals	234.0	914.0	1.26	11.0	43.8	171.0	1.00	3.84	121.0	352.0

EUG-02: Grandfathered Steam Generators

Emissions from EUG-02 are based on AP-42 (1/95) as a primary reference, with modifications and updates since January 1995 as identified below. Combustion factors were found in Sections 1.2, 1.3, and 1.4. NO_x and SO₂ emissions are based on CEMS data of units 1A, 1B, 2, and 3.

The facility is also subject to Acid Rain Renewal Permit No. 2024-0454-ARR5. For US EPA Regional Haze compliance, Unit 2 has a NO_x limit of 0.22 lb/MMBTU, rolling 30-day averages.

EUG-02 Total Emissions

Point Source	NO _x		SO ₂		PM _{10/2.5}		VOC		CO	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2	2,139	5,530 ⁽¹⁾	2.80	12.3	35.4	155.0	25.6	112.0	352	1,541
Totals	2,139	5,530⁽¹⁾	2.80	12.3	35.4	155.0	25.6	112.0	352	1,541

⁽¹⁾ Per the SARHA

Emissions of HAP for EUG-02 are based on AP-42 (7/98), Table 1.4-3 for organic compounds and Table 1.4-4 for metals.

EUG-02 HAP Emissions

Pollutant	Factor	Unit 2	
	lb/MMBtu	lb/hr	TPY
Arsenic	1.97E-07	0.00094	0.0041
Benzene	2.07E-06	0.0098	0.043
Cadmium	1.08E-06	0.0052	0.023
Chromium	1.38E-06	0.0066	0.029
Cobalt	8.28E-08	0.00039	0.0017
Dichlorobenzene	1.18E-06	0.0056	0.025
Formaldehyde	7.39E-05	0.35	1.5
Hexane	1.77E-03	8.4	37.0
Manganese	3.74E-07	0.0018	0.0078
Mercury	2.56E-07	0.0012	0.0053
Naphthalene	6.01E-07	0.0029	0.013
Nickel	2.07E-06	0.0098	0.043
Toluene	3.35E-06	0.016	0.07
Totals		8.81	38.77

EUG-03: Steam Generators

Emissions of PM and VOC from EUG-03 are based on AP-42 (4/26), Section 1.4. NO_x and SO₂ emissions are based on CEMS data of units 1A, 1B, 2, and 3. The established CO BACT emission limit is 0.530 lb/MMBTU (Per Permit No. 2003-410-C (M-6) PSD). Except for NO_x, annual emissions are based on 8,365,811 MMBTU/YR (equivalent to a 20% annual capacity factor).

The facility is also subject to Acid Rain Renewal Permit No. 2024-0454-ARR5. For US EPA Regional Haze compliance, Unit 3 has a NO_x limit of 0.15 lb/MMBTU, rolling 30-day averages.

EUG-03 Total Emissions

Point Source	NO _x		SO ₂		PM _{10/2.5}		VOC		CO	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
3	716.25	300.0	2.82	2.47	35.75	31.32	25.87	22.67	2,530.75	2,216.94
Totals	716.25	300.0	2.82	2.47	35.75	31.32	25.87	22.67	2,530.75	2,216.94

Emissions of HAP for EUG-03 are based on AP-42 (7/98), Table 1.4-3 for organic compounds and Table 1.4-4 for metals.

EUG-03 HAP Emissions

Pollutant	Factor	Unit 3	
	lb/MMBtu	lb/hr	TPY
Benzene	2.07E-06	0.0099	0.0087
Cadmium	1.08E-06	0.0052	0.0045

Pollutant	Factor	Unit 3	
	lb/MMBtu	lb/hr	TPY
Chromium	1.38E-06	0.0066	0.0058
Dichlorobenzene	1.18E-06	0.0056	0.0049
Formaldehyde	7.39E-05	0.35	0.31
Hexane	1.77E-03	8.50	7.40
Manganese	3.74E-07	0.0018	0.0016
Mercury	2.56E-07	0.0012	0.0011
Naphthalene	6.01E-07	0.0029	0.0025
Nickel	2.07E-06	0.0099	0.0087
Toluene	3.35E-06	0.016	0.014
Totals		8.91	7.76

EUG-Aux 2: Steam Generator

Emissions from Aux 2 are based on manufactures data, a 21% annual capacity factor (1,840 hr/yr), and the maximum heat input rating of 276.5 MMBTUH.

EUG-Aux 2 Emissions

Pollutant	Emission Factor	272.4 MCFH (lb/hr)	501.1 MMCFY (TPY)
TSP = PM ₁₀	0.02 lb/MMBTU	5.53	5.09
SO ₂	0.0014 lb/MMBTU	0.39	0.36
NO _x	0.15 lb/MMBTU	41.48	38.15
CO	0.296 lb/MMBTU	81.83	75.28
VOC	0.005 lb/MMBTU	1.38	1.27

Emissions of HAP for EUG-Aux 2 are based on AP-42 (7/98), Table 1.4-3 for organic compounds and Table 1.4-4 for metals.

EUG-Aux 2 HAP Emissions

Pollutant	Factor	Aux 2	
	lb/MMBtu	lb/hr	TPY
Formaldehyde	7.39E-05	0.02	0.019
Hexane	1.77E-03	0.49	0.45
Totals		0.51	0.47

EUG-Aux 3: Steam Generator

Emissions of CO, VOC, PM, and SO₂ from Aux 3 are based on AP-42 (7/98), Section 1.4, a gas heating value of 1,020 BTU/SCF, a 26% annual capacity factor (2,277 hr/yr), and a rating that will not exceed 544,346 MMBTU/YR. Emissions of NO_x are based on manufacture specifications.

EUG-Aux 3 Emissions

Pollutant	Emission Factor	232 MCFH (lb/hr)	528 MMCFY (TPY)
TSP = PM ₁₀	7.6 lb/MMSCF	1.76	1.97

Pollutant	Emission Factor	232 MCFH (lb/hr)	528 MMCFY (TPY)
SO ₂	0.6 lb/MMSCF	0.14	0.16
NO _x	140 lb/MMSCF	32.48	36.26
CO	84 lb/MMSCF	19.49	21.76
VOC	5.5 lb/MMSCF	1.28	1.42

Emissions of HAP for EUG-Aux 3 are based on AP-42 (7/98), Table 1.4-3 for organic compounds and Table 1.4-4 for metals.

EUG-Aux 3 HAP Emissions

Pollutant	Factor	Aux 3	
	lb/MMBtu	lb/hr	TPY
Formaldehyde	7.39E-05	0.018	0.02
Hexane	1.77E-03	0.42	0.48
Totals		0.44	0.50

EUG-16: Emergency Engines

Emission from EUG-16 are based on AP-42 (1/96), Section 3.4, Table 3.4-1 for large stationary diesel engines. The sulfur content of the diesel fuel is 0.0015%.

GEN 1/2 and GEN 3 are emergency engines and are calculated based on 100 hours of operation per year.

Engine Emission Factors

ID#	NO _x	CO	SO _x	PM _{10/2.5}	VOC
	lb/hp-hr	lb/hp-hr	lb/hp-hr	lb/hp-hr	lb/hp-hr
GEN 1/2	0.024	0.005	0.0000121	0.0007	0.000642
GEN 3	0.024	0.005	0.0000121	0.0007	0.000642

Engine Emissions

ID#	NO _x		CO		SO _x		PM _{10/2.5}		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
GEN 1/2	86.40	4.32	19.80	0.99	0.04	<0.01	2.52	0.13	2.31	0.12
GEN 3	35.42	1.77	8.12	0.41	0.02	<0.01	1.03	0.05	0.95	0.05

Emissions of HAP from EUG-16 are based on AP-42 (4/25), Section 3.4, Table 3.4-3 for uncontrolled diesel engines.

Engine HAP Emissions

Pollutant	Emission Factor	GEN 1/2		GEN 3	
	lb/MMBTU	lb/hr	TPY	lb/hr	TPY
Acetaldehyde	2.0E-07	0.00073	0.00004	0.00030	0.00001
Acrolein	6.3E-08	0.00023	0.00001	0.00009	<0.00001
Benzene	6.2E-06	0.02235	0.00112	0.00916	0.00046

Pollutant	Emission Factor	GEN 1/2		GEN 3	
	lb/MMBTU	lb/hr	TPY	lb/hr	TPY
Formaldehyde	6.3E-07	0.00227	0.00011	0.00093	0.00005
PAH	1.7E-06	0.02235	0.00112	0.00916	0.00046
Toluene	2.2E-06	0.00809	0.00040	0.00332	0.00017
Xylenes	1.5E-06	0.00556	0.00028	0.00228	0.00011
Totals		0.06158	0.00308	0.00126	0.00126

EUG-16 Total Emissions

Point Source	NO _x	CO	SO _x	PM _{10/2.5}	VOC	HAP
	TPY	TPY	TPY	TPY	TPY	TPY
GEN 1/2	4.32	0.99	<0.01	0.13	0.12	<0.01
GEN 3	1.77	0.41	<0.01	0.05	0.05	<0.01
Totals	6.09	1.40	<0.01	0.18	0.17	<0.01

EUG-Chem: Stored Chemicals

Emissions from EUG-Chem are considered negligible.

EUG-Insignificant Sources

Emissions from Insignificant Sources are considered negligible.

EUG-20: SCCTs

Emissions from SCCT 5 and SCCT 6 are based on the manufacturers' data used to establish the BACT emission limits. Maximum potential hourly emission rates were provided by GE for NO_x, CO, VOC, PM, PM₁₀, PM_{2.5}, and GHG (as CO₂e) shown in the table below. Emissions of SO₂ are based on fuel heat input of 2,289.6 MMBTUH and a maximum sulfur content of 0.5 gr S/100 scf. Emissions of H₂SO₄ are based on the assumption that 15% of total sulfur is converted to SO₃ and that all SO₃ will react with water to form H₂SO₄.

PSO proposes a 33.33% annual capacity factor limitation for SCCT 5 and SCCT 6, resulting in annual emissions being based on 2,920 hours per year operating at maximum capacity. PSO estimates 300 annual events for Startup and Shutdown operations, which would equate to 155 hours of uncontrolled emissions per year. Emissions of SO₂, H₂SO₄, GHG, and HAPs during SUSD are assumed to be no more than emissions from normal operations.

SCCT Emissions (per SCCT)

Pollutant	Factor (lb/MMBTU)	Hourly Rate (lb/hr)	Annual Rate (TPY)
NO _x	0.034	78.46	108.48 ⁽¹⁾
CO	0.0156	35.67	49.31 ⁽¹⁾
VOC	0.0015	3.47	4.79 ⁽¹⁾
SO ₂	0.0014	3.14	4.59 ⁽²⁾
PM _{10/2.5}	0.0031	7.00	10.23 ⁽²⁾

Pollutant	Factor (lb/MMBTU)	Hourly Rate (lb/hr)	Annual Rate (TPY)
H ₂ SO ₄	0.00011	0.24	0.35 ⁽²⁾
GHG	123.12	281,903.04	411,578.44 ⁽²⁾

⁽¹⁾ Based on 2,765 hours of operation a year.

⁽²⁾ Based on 2,920 hours of operation a year.

Emissions of HAPs are based on emissions factors from AP-42 (4/00), Section 3.1 and a fuel input of 2,271.1 MMBTUH. Emissions of formaldehyde are based on manufacture's data.

SCCT HAP Emission (per SCCT)

Pollutant	Emission Factor (lb/MMBTU)	Hourly Rate (lb/hr)	Annual Rate (TPY) ⁽¹⁾
1,3-Butadiene	4.30E-07	0.001	0.001
Acetaldehyde	4.00E-05	0.09	0.13
Acrolein	6.40E-06	0.01	0.02
Benzene	1.20E-05	0.03	0.04
Ethylbenzene	3.20E-05	0.07	0.11
Formaldehyde	- ⁽²⁾	0.52	0.76
Napthalene	1.30E-06	0.003	0.004
PAH	2.20E-06	0.005	0.007
Propylene Oxide	2.90E-05	0.07	0.10
Toluene	1.30E-04	0.30	0.43
Xylene	6.40E-05	0.15	0.21
Total HAPs		1.24	1.82

⁽¹⁾ Annual emissions are based on 2,920 hours of operation a year.

⁽²⁾ Formaldehyde emissions are based on manufacture's data.

Emissions of NO_x, CO, and VOC from Startup and Shutdown operations are based on worst-case hourly scenarios for each SUSD event. Emissions of PM_{10/2.5}, SO₂, H₂SO₄, GHG, and HAPs during SUSD are assumed to be no more than emissions from normal operations.

SCCT SUSD Emission Factors

Pollutant	18-minutes Startup Uncontrolled (lb/event)	13-minutes Shutdown Uncontrolled (lb/event)	Total SUSD (lb/event)
NO _x	57.8	31.9	89.70
CO	396.7	252.7	649.40
VOC	45.2	22.6	67.80

The time frame for one startup and shut down event is 18 and 13 minutes respectively. PSO expects each turbine to have no more than 300 events per year, or 155 hours per year.

SCCT SUSD Emissions

ID#	NO _x		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
SCCT 5	173.68	13.46	1,256.9	97.41	131.23	10.17

ID#	NO _x		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
SCCT 6	173.68	13.46	1,256.9	97.41	131.23	10.17

EUG-20 Total Emissions

Point Source	NO _x	CO	VOC	SO ₂	PM _{10/2.5}	H ₂ SO ₄	GHG	HAP
	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY
SCCT 5	121.94	146.73	14.96	4.59	10.23	0.35	411,578	1.82
SCCT 6	121.94	146.73	14.96	4.59	10.23	0.35	411,578	1.82
Totals	243.88	293.46	29.92	9.18	20.46	0.70	823,156	3.64

EUG-21: HTRs

Emissions of NO_x, CO, VOC, and PM from HTR 1 and HTR 2 are based on emission factors from manufacturers data used to establish the BACT emission limits, a gas heating value of 1,020 BTU/SCF, and a rating of 2.5 MMBTUH. Emissions factors for SO₂ and GHG are based on AP-42 (7/98), Section 1.4. PSO proposes a 33% annual capacity factor limitation for HTR 1 and HTR 2, resulting in annual emissions being based on 2,920 hours per year.

Heater Emission Factors

ID#	NO _x	CO	VOC	SO ₂	PM _{10/2.5}	GHG
	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU
HTR 1	0.011	0.0745	0.0149	0.0006	0.0081	117.65
HTR 2						

Heater Emissions

ID#	Rating	NO _x	CO	VOC	SO ₂	PM _{10/2.5}	GHG
	MMBTUH	TPY	TPY	TPY	TPY	TPY	TPY
HTR 1	2.5 ⁽¹⁾	0.04	0.27	0.05	<0.01	0.03	429.41
HTR 2	2.5 ⁽¹⁾	0.04	0.27	0.05	<0.01	0.03	429.41

⁽¹⁾ Annual emissions are based on 2,920 hours of operation a year.

Facility-Wide Emissions

EUG	Description	NO _x	CO	VOC	PM ₁₀	PM _{2.5}	SO ₂
		TPY	TPY	TPY	TPY	TPY	TPY
EUG-01	Turbines and HRSG	914.0	474.0	3.84	171.0	171.0	11.0
EUG-02	Grandfathered Steam Generator	5,530	1,541	112.0	155.0	155.0	12.3
EUG-03	Steam Generator	300.0	2,216.9	22.67	31.32	31.32	2.47
EUG-Aux 2	Steam Generator	38.15	75.28	1.27	5.09	5.09	0.36
EUG-Aux 3	Steam Generator	36.26	21.76	1.42	1.97	1.97	0.16
EUG-16	Emergency Engines	6.09	1.40	0.17	0.18	0.18	<0.01
EUG-Chem	Stored Chemicals	-	-	-	-	-	-

EUG	Description	NO _x	CO	VOC	PM ₁₀	PM _{2.5}	SO ₂
		TPY	TPY	TPY	TPY	TPY	TPY
EUG-20	SCCTs	243.88	293.46	29.92	20.46	20.46	9.18
EUG-21	HTRs	0.04	0.27	0.05	0.03	0.03	<0.01
Totals		7,068.4	4,624.1	171.34	385.05	385.05	35.47
Emissions from Permit No. 2019-0607-C (M-1)		6,801.9	4,253.5	140.20	359.40	359.40	25.60
Change in Emissions		266.52	370.57	31.14	25.65	25.65	9.87

HAP Emissions

EUG	Description	HAPs	
		lb/hr	TPY
EUG-01	Turbines and HRSG	4.14	18.1
EUG-02	Grandfathered Steam Generator	8.81	38.77
EUG-03	Steam Generator	8.91	7.76
EUG-Aux 2	Steam Generator	0.51	0.47
EUG-Aux 3	Steam Generator	0.44	0.50
EUG-16	Emergency Engines	<0.01	<0.01
EUG-Chem	Stored Chemicals	-	-
EUG-20	SCCTs	2.48	3.64
EUG-21	HTRs	<0.01	<0.01
Totals		25.29	69.24
Emissions from Permit No. 2019-607-C (M-1)		20.89	86.76
Change in Emissions		4.4	(17.52)

The total HAP emissions from the PSO equipment at the facility is 69.54 TPY (37.0 TPY of Hexane). Therefore, the individual and the total emissions of HAPs do exceed the major source thresholds of 10/25 TPY and would be considered a major source of HAP.

SECTION XI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified on Part 1b of the forms in the application and duplicated below were confirmed by the initial operating permit inspection. Records were available to confirm the insignificance of the activities. Appropriate record keeping of activities indicated below with “*” is specified in the Specific Conditions.

- (1) *Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period
- (2) *Emissions from storage tanks constructed with a capacity less than 39,894 gallons that store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. PSO has three diesel fuel tanks; (#1) 31,500 gallons (Unit 1/2 emergency generator), (#2) 13,800

gallons (Unit 3 emergency generator), and (#3) 12,000 gallons (for mobile vehicles). PSO also has five lube oil storage tanks, including #6, #7, #9, & #10 with 13,860 gallons capacity each, and #8 with 12,400 gallons capacity. None of these tanks are subject to NSPS or to State rules due to construction in the early 1970's, and all store liquids with vapor pressure well below the 1.5 psia threshold.

- (3) *Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure of less than or equal to 1.0 psia at maximum storage temperature. PSO has a natural gas condensate tank (#5) with capacity of 8,459 gallons.
- (4) *The facility proposed a number of sources as insignificant because their emissions are below the 5 TPY State *de minimis* and they are not subject to NSPS, NESHAP, or State rules.
 - a. The fly ash landfill (capped and closed / no longer active following the cessation of coal combustion in Unit 3).
 - b. Cold degreasing operations.
 - c. Torch cutting and welding is used only for maintenance purposes, qualifying it as a Trivial Activity, for which no recordkeeping is necessary.
 - d. Welding and soldering are used only for maintenance purposes, qualifying it as a Trivial Activity, for which no recordkeeping is necessary.
 - e. Hazardous waste and hazardous materials drum staging areas.
 - f. Surface coating operations are performed only for maintenance purposes, qualifying it as a Trivial Activity, for which no recordkeeping is necessary.
 - g. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets.
 - h. Hand wiping and spraying of solvents from containers with less than one liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. Rogers County is in an ozone attainment area.

SECTION XII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]

Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources)

[Applicable]

Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAP or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the operating permit application, or are developed from the applicable requirement.

Section 8-4 requires a construction permit prior to the following:

- Construction of a new source that would require an operating permit under 40 CFR Part 70;
- Reconstruction of a major HAP source under 40 CFR Part 63;
- Any physical change or change in method of operation that would be significant modification under OAC 252:100-8-7.2(b)(2); or
- Any physical change or change in method of operation that would increase the PTE of any one regulated air pollutant by more than 10 TPY, calculated using the approach in 40 CFR § 40.153(b).

The change requested in M-1 is to replace the existing NO_x limit of 0.28 lb/MMBTU for Unit 2 with the proposed SARHA limit of 0.22 lb/MMBTU. Since this is a more stringent limit for offset purposes, it does not require any further BART review. However, the SARHA will require the new limits and/or requirements to be included in a NSR construction permit. The requested change in M-1 has already been incorporated in Permit No. 2019-0607-C (M-1), issued on March 9, 2026. For PSD purposes, M-1 and M-2 were aggregated into a single project for review.

The change requested in M-2 is to replace the burner on Auxiliary Boiler 3 with a new, low NO_x burner and establish a 26% annual capacity factor limit. The replacement of the burner itself does meet the definition of modification in 40 CFR § 60.14, however, increasing the annual capacity factor limit from 10% to the new 26% would require a construction permit.

The change requested in M-3 is to construct two SCCTs and two FGHs, four new sources that would require a construction permit.

The change requested in M-4 is to replace Auxiliary Boiler 1/2 and establish a 21% annual capacity factor limit which would require a construction permit.

OAC 252:100-9 (Excess Emissions Reporting Requirements)

[Applicable]

Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning)

[Applicable]

Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter)

[Applicable]

Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. Thus, the turbines, heaters, boilers, and generators are subject to the requirements of this subchapter. OAC 252:100, Appendix C specifies a PM emission limitation of 0.60 lb/MMBTU for all equipment at this facility with a heat input rating of 10 MMBTUH or less. OAC 252:100, Appendix C specifies a PM emission limitation for all equipment at this facility with a heat input rating of greater than 10-MMBTUH, but less than 1,000-MMBTUH based on the following calculation: $E = 1.0428080X^{-0.238561}$, where E is the allowable emission rate and X is the maximum heat input. Appendix C specifies a PM emission limitation for all equipment at this facility with a heat input rating greater than 1,000-MMBTUH, but less than 10,000-MMBTU based on the following calculation: $E = 1.60X^{-0.30103}$, where E is the allowable emission rate and X is the maximum heat input. This permit requires the use of natural gas for all fuel-burning equipment to ensure compliance with Subchapter 19.

ID #	Equipment	Maximum Heat Input (MMBTUH)	Emissions (lb/MMBTU)	
			Appendix C	Potential
1A and 1B	Gas Turbines (each)	1,684	0.171	0.011
	HRSGs (each)	99	0.348	0.01
2	Unit 2 Boiler	4,754	0.125	0.0074
3	Unit 3 Boiler	4,775	0.125	0.0074
Aux 2	Auxiliary Boiler 2	276.5	0.273	0.02
Aux 3	Auxiliary Boiler 3	239	0.282	0.0074
GEN 1/2	3,600-hp emergency diesel generator	124	0.468	0.0618
GEN 3	1,476-hp emergency diesel generator	50	0.579	0.213

ID #	Equipment	Maximum Heat Input (MMBTUH)	Emissions (lb/MMBTU)	
			Appendix C	Potential
SCCT 5	Simple Cycle Combustion Turbine	2,290	0.156	0.003
SCCT 6	Simple Cycle Combustion Turbine	2,290	0.156	0.003
FGH 1	Fuel Gas Heater	2.5	0.60	0.008
FGH 2	Fuel Gas Heater	2.5	0.60	0.008

OAC 252:100-25 (Visible Emissions and Particulates)

[Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas, there is very little possibility of exceeding the opacity standards.

Continuous monitoring of opacity (COM) is required for fossil fuel-fired steam generators in accordance with 40 CFR Part 51, Appendix P and any fuel-burning equipment with a design heat input value of 250 MMBTUH or more, that does not burn gaseous fuel exclusively, and that was not in being on or before July 1, 1972, or that is modified after July 1, 1972. 40 CFR Part 51, Appendix P exempts fossil fuel-fired steam generators from the COM requirements when gaseous fuel is the only fuel burned. This section does not apply to sources that are subject to a NSPS promulgated in 40 CFR Part 60. Since all Northeastern units of a size greater than the threshold only burn natural gas, they are exempt from the opacity monitor requirements. The proposed combustion turbines, which have a heating value greater than 250 MMBTUH, will burn gaseous fuel exclusively and are also not subject.

OAC 252:100-29 (Fugitive Dust)

[Applicable]

No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Some haul roads are not paved. Fugitive dust emissions are minimized by using water wagons on the haul roads, and parking area. Fugitive emissions reduction activities have been incorporated into the permit. No additional controls are necessary.

OAC 252:100-31 (Sulfur Compounds)

[Applicable]

Part 2, Section 31-7, limits the allowable H₂S ambient air concentrations for new and existing sources. Emissions of H₂S shall not cause an ambient air concentration of H₂S greater than 0.2 ppm, on a 24-hour average, at standard conditions. Fuel-burning equipment fired with pipeline natural gas or No. 2 diesel with a sulfur content of 15 ppm will not have the potential to exceed the H₂S ambient air concentration limit.

Part 3, Section 31-16, contains existing equipment standards for existing fossil fuel steam generators. Any fossil fuel-fired steam generator unit that was in being on or before July 1, 1972, shall install, calibrate, maintain, and operate an SO₂ CEM for any fossil fuel-fired steam generator that utilizes an air pollution abatement operation to reduce the emissions of sulfur oxides.

Unit 2 was constructed prior July 1, 1972, but does not use an air pollution abatement operation to reduce the emissions of sulfur oxides. Therefore, it is not subject to this rule.

Part 5 of the subchapter sets “new” equipment standards, which limit SO₂ emissions to 0.2 lbs/MMBTU for gas fuel, 0.8 lbs/MMBTU for liquid fuel, and 1.2 lbs/MMBTU for solid fuel. Units 1A, 1B, 3, and auxiliary boiler 2 and 3 were installed after July 1, 1972, and are considered new fuel-burning equipment. Units 1A, 1B, 2, 3, and auxiliary boiler 2 and 3 have SO₂ emissions of 0.0014 lbs/MMBTU from combustion of pipeline natural gas with a sulfur content of 0.5 gr/100 SCF. The diesel fired engines will have emissions of 0.0015 lb/MMBTU from combustion of ultra-low sulfur diesel fuel with a sulfur content of 15 ppmw. Thus, all units are in compliance.

Any fuel-burning equipment with design heat input values of 250 MMBTUH or more is required to install, calibrate, maintain, and operate a SO₂ CEM, except where:

- gaseous fuel containing less than 0.1% by weight sulfur (0.29 gr/scf or approximately 500 ppmv at standard conditions on a dry basis) is the only fuel burned; or
- a solid or liquid fuel sampling and analysis method is used to determine SO₂ emission compliance.

The boilers and turbines are rated greater than 250 MMBTUH. However, when burning pipeline natural gas, the facility is not required to have an SO₂ CEMS and will demonstrate compliance using fuel records.

OAC 252:100-33 (Nitrogen Oxides)

[Applicable]

This subchapter limits NO_x emissions from new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NO_x per MMBTU. NO_x emission limits for various fuels are set at 0.20 lbs/MMBTU for gas, 0.30 lbs/MMBTU for oil (liquid), and 0.70 lbs/MMBTU for solid fossil fuel. Unit 3 and the auxiliary boilers were constructed after February 14, 1972, and are defined as new fuel-burning equipment. NO_x emissions from the Unit 3 stack are less than the listed standards for each type of fuel as indicated in the emission section. Addition of the low-NO_x burners decreased emissions below the already acceptable levels, and the refined tuning approved under Permit No. 2003-410-C (M-6) PSD further decreased emissions. NO_x emissions from the auxiliary boilers have a manufacturer’s suggested value of 0.12 lbs/MMBTU. Therefore, all units will remain in compliance.

The definition of fuel-burning equipment was modified on July 1, 1997, to include gas turbines. Units 1A, 1B, 5, and 6 were constructed after that date and are also considered new fuel-burning equipment and are subject to the NO_x emission limits for gas fired fuel burning equipment. The emissions of NO_x from Units 1A and 1B are estimated at 0.09 lb/MMBTU, with Units 5 and 6 being 0.033 lb/MMBTU, which is in compliance with the standard.

OAC 252:100-35 (Carbon Monoxide)

[Not Applicable]

None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds)

[Applicable]

Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The fuel oil and lube oil at the facility are below the 1.5 psia vapor pressure requirement and are therefore exempt. The liquid natural gas condensate tank is primary water (>99%) and therefore has a vapor pressure below the 1.5 psia requirement. The 2,000-gal gasoline tank is filled through a permanent submerged pipe and is in compliance.

Part 3 requires loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading. Therefore, this requirement is not applicable.

Part 5 limits the VOC content of coating of parts and products. Any painting operation will involve maintenance coatings of buildings and equipment and emit less than 100 pounds per day of VOCs and so is exempt.

Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. The equipment at this location is subject to this requirement. Based on manufacturer's data and good engineering practice, the equipment must not be overloaded, and temperature and available air must be sufficient to provide essentially complete combustion. Extensive monitoring of stack emissions is performed and is adequate to assure compliance with the requirements of OAC 252:100-37-36.

Part 7 requires all effluent water separator openings that receive water containing more than 200 gallons per day of any VOC, to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.

OAC 252:100-42 (Toxic Air Contaminants (TAC))

[Applicable]

This subchapter regulates TAC that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping)

[Applicable]

This subchapter provides general requirements for testing, monitoring, and record keeping. It applies to any testing, monitoring, or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain, and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any

credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

Each emissions unit was evaluated for periodic testing in accordance with the Periodic Testing Standardization guidance issued December 1, 2011, on a pollutant-by-pollutant basis. The frequency of the periodic testing requirement is based on the quantity of the pollutant emitted. Periodic testing requirements are not required for an emission unit that is subject to an applicable requirement that already requires periodic testing or CEM. For this facility, only pollutants greater than 40 TPY for each emission unit were evaluated.

Periodic Testing Review

ID#	Pollutant	TPY	Current Monitoring	Periodic Testing
Unit 1A (Turbine)	NO _x	418	Part 60/75 CEMS	-
	CO	198.0	-	Yes – Every Five Years
Unit 1B (Turbine)	NO _x	418	Part 60/75 CEMS	-
	CO	198.0	-	Yes – Every Five Years
Unit 2	NO _x	5,530	Part 60/75 CEMS	-
	CO	1,541	-	Yes – Every Year
Unit 3	NO _x	300.0	Part 60/75 CEMS	-
	CO	2,216.94	-	Yes – Every Year
Aux 2	CO	64.46	-	Yes – Every Five Years
SCCT 5	NO _x	121.93	Part 60/75 CEMS	-
	CO	146.73	Part 60/75 CEMS	-
SCCT 6	NO _x	121.93	Part 60/75 CEMS	-
	CO	146.73	Part 60/75 CEMS	-

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-7	Minor Facilities	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Landfills	not in source category

SECTION XIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52

[Applicable]

The facility is considered an existing major source for PSD. The requested permit modifications for M-3 result in a significant emissions increase and a significant net emissions increase greater than the PSD Significant Emission Rate (SER) for NO_x, CO, PM₁₀, PM_{2.5}, and CO_{2e}. The project emissions increase analysis review is presented in Section IV of this Memorandum. The required

BACT Analysis and Ambient Air Impact Analysis are presented in Sections V and VI, respectively. Any future projects will be evaluated in comparison to the PSD SER: 40 TPY NO_x, 100 TPY CO, 40 TPY VOC, 40 TPY SO₂, 15 TPY PM₁₀, 10 TPY PM_{2.5}, and 75,000 TPY CO_{2e}.

NSPS, 40 CFR Part 60 [Subparts A, D, Db, Dc, GG, KKKKa, and TTTTa Applicable]

Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction of any affected facility, the facility must notify DEQ that construction has commenced. A notification of the actual date of initial start-up of any affected facility will be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial start-up of the facility. The facility must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ. This facility is applicable to this subpart.

Subpart D, Fossil-Fuel-Fired Steam Generators. The affected facilities to which the provisions of this subpart applies to are the following that have commenced construction or modification after August 17, 1971: Each fossil-fuel-fired steam generating unit of more than 73-MW heat input rate (250-MMBTUH), and each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBTUH).

Unit 2 exceeds the 250 MMBTUH threshold, but commenced construction much earlier than its start-up date of 1970, and has not been modified. Therefore, it is not an affected facility. The auxiliary boiler for Units 1 and 2 have been replaced with a newly constructed boiler (auxiliary boiler 2) that is estimated to be constructed in 2026 with a new rating of 276.5 MMBTUH, which is above the threshold, however, per 40 CFR §60.40b(j) any affected facility applicable under NSPS Subpart Db and has commenced construction, modification, or construction after June 19, 1986, is not subject to Subpart D. Therefore, it is not an affected facility. Construction of Unit 3 commenced in 1974. Unit 3 is subject to this subpart. Applicable requirements for Unit 3 include:

- Exempt - 40 CFR §60.42 establishes a particulate matter emission limit and an opacity standard for various fossil fuels. Because Unit 3 will combust only natural gas, it is exempt from the PM and opacity standards per §60.42(d).
- 40 CFR §60.43(a) and (b) establishes sulfur dioxide emission limits of 1.2 lbs/MMBtu for solid fossil fuels and 0.8 lbs/MMBtu for liquid fossil fuels, and wood residue. There are no SO₂ emissions limits for natural gas. Because Unit 3 will combust only natural gas, compliance with 40 CFR §60.43(c) is based on fuel records.
- 40 CFR §60.44 establishes a nitrogen oxides limit of 0.20 lb/MMBTU for gaseous fossil fuel.
- 40 CFR §60.45 establishes requirements and criteria for the operation of continuous monitoring systems for nitrogen oxides and either oxygen or carbon dioxide. Because Unit 3 will combust only natural gas, COMS and CEMS for sulfur dioxide are not required per 40 CFR §60.45(b)(1).
- 40 CFR §60.46 describes test methods in detail, including Appendix A Reference Methods to be used, general requirements per 40 CFR §60.8, and factors to be used in calculations.

As demonstrated in the Emissions section above, the facility is in compliance with the limits set in §§60.44. The continuous emissions monitoring system (CEMS) installed to demonstrate compliance with 40 CFR Part 75 satisfies the criteria of §§60.45 and 60.46.

Subpart Da, Electric Utility Steam Generating Units. The affected facility to which this subpart applies is each electric utility steam generating unit that is capable of combustion more than 73 MW (250 MMBTUH) heat input of fossil fuel and for which construction, modification, or reconstruction commenced after September 18, 1978. The HRSGs associated with EUG-01 are rated at 99 MMBTUH and do not exceed the applicability threshold. Therefore, this facility is not subject to this subpart.

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 MMBTUH). The HRSGs associated with EUG-01 are rated at 99 MMBTUH and do not exceed the threshold. EUG-Aux 2 was replaced/constructed in 2026 and is above the applicability threshold. Therefore, this facility is subject to this subpart. Auxiliary 2 will only combust natural gas and is therefore not subject to a PM or SO₂ standard but is subject to a NO_x standard. Per § 60.44b(a), the applicable NO_x emissions standard is 0.20 lb/MMBTU. All applicable requirements are incorporated into the permit.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. The affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 MW (100 MMBTUH) or less, but greater than or equal to 2.9 MW (10 MMBTUH). The turbines located at the facility fits the definition of a “combined cycle system” and the HRSG units fit the definition of “steam generating unit” as both are found in 40 CFR §60.41c, so the duct burners are subject to Subpart Dc. Particulate and SO₂ standards are not set for gas-fired units. The only applicable standards are initial notification (§60.48c(a)) and a requirement to keep records of the fuels used (§60.48c(g)).

Subpart K, Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. The affected facility to which this subpart applies to is each storage vessel for petroleum liquids which has a storage capacity greater than 40,000 gallons. The following six tanks were constructed before the applicability date: Tank No. 11, with a capacity of 4,200,000 gallons of No. 2 fuel oil which has been closed for several years and is no longer in service; Tank No. 10, owned by Enable Gas Services, with a capacity of 8,459 gallons of natural gas condensate; Tank No. 7, with a shell capacity of 6,300 gallons; Tank No. 8, with a shell capacity of 6,300 gallons (two tanks within one shell tank with a dividing wall) with a capacity of 12,600 gallons of lube oil; and Tank No. 5 and 6, each with a capacity of 13,800 gallons of lube oil. (New tank numbers and capacities are from the NES 1-2 SPCC Plan. All previous tank numbers are from legacy accounting).

Tank No. 4 was constructed prior to June 11, 1973, but before May 19, 1978. The NE12 emergency generator tank has a capacity of 750-bbl (31,500 gallons) which is less than the affected source threshold. Therefore, this facility is not subject to this subpart.

Subpart Ka, Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984. The affected facility to which this subpart applies to is each storage vessel for petroleum liquids which has a storage capacity greater than 40,000 gallons. The following three tanks at the facility were constructed between May 18, 1978 but before July 23, 1984: Tank No. 8, with a capacity of 13,800 gallons (Unit 3 emergency generator, installed Feb. 19, 1979); Tank No. 6 and 7, each with a capacity of 13,860 gallons lube oil. All tanks are less than the affected source threshold. Therefore, this facility is not subject to this subpart.

Subpart Kb, Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023. This subpart regulates hydrocarbon storage tanks larger than 19,813 gallons capacity. Tank No. 5 was constructed in 1993 with a capacity less than 19,813 gallons. Therefore, this facility is not subject to this subpart.

Subpart Kc, Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023. This subpart regulates hydrocarbon storage tanks larger than 20,000 gallons capacity and built after October 4, 2023. No tanks with a capacity greater than 20,000 gallons have been constructed after October 4, 2023. Therefore, this facility is not subject to this subpart.

Subpart GG, Stationary Gas Turbines. The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired and which that construction, modification, or reconstruction commences after October 3, 1977.

EUG-01 turbines have LHV heat input capacities of 1,712 MMBTUH at peak load and are subject. The turbines are governed by 40 CFR §60.332(b) and must satisfy the NO_x standard set forth in §60.332(a)(1). As applied to these turbines, the formula yields an upper limit of 100 ppmvd. For NO_x emissions, the BACT requirement, as established in Permit No. 96-288-C (PSD), of 15 ppmvd is more stringent than Subpart GG and is applicable. Testing fuel for nitrogen content was addressed in a letter dated May 17, 1996, from EPA Region 6. Monitoring of fuel nitrogen content shall not be required when pipeline-quality natural gas is the only fuel fired in the turbine.

Sulfur dioxide standards specify that no fuel that exceeds 0.8% by weight sulfur shall be used, nor shall exhaust gases contain in excess of 150 ppm SO₂. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply; these custom schedules must be approved by the Administrator before they can be used for compliance with monitoring requirements. The EPA Region 6 letter referenced above also states that when pipeline-quality natural gas is used exclusively, acceptable monitoring for sulfur is a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly “stain tube” analysis.

The proposed turbines in EUG-20 meets the definition of affected facility for this subpart, however, per NSPS Subpart KKKKa § 60.4305a(b), stationary combustion turbines regulated under Subpart KKKKa are exempt from the requirements of Subpart GG. Since EUG-20 is subject to NSPS Subpart KKKKa, it is exempt from the requirements of this subpart. Therefore, EUG-20 is not subject to this subpart.

Subpart IIII, Stationary Compression Ignition Internal Combustion Engines. The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) constructed after July 11, 2005. There is no stationary engines at this facility. Therefore, this facility is not applicable to this subpart. The engines in EUG-16 were constructed prior to the applicability date. Therefore, this facility is not subject to this subpart.

Subpart JJJJ, Stationary Spark Ignition (SI) ICE. This subpart promulgates emission standards for all new SI engines ordered after June 12, 2006, and all SI engines modified or reconstructed after June 12, 2006, regardless of size. There is no stationary SI-ICE at this facility and is therefore not applicable to this subpart.

Subpart KKKK, Stationary Combustion Turbines. You are subject to this subpart if you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. The turbines located in EUG-01 were constructed prior to the applicability date and have not been modified.

The proposed turbines in EUG-20 will have peak heat inputs greater than 10 MMBTUH. However, the proposed turbines will also have commenced construction after December 13, 2024. Per NSPS Subpart KKKKa § 60.4305a(b), stationary combustion turbines regulated under Subpart KKKKa are exempt from the requirements of Subpart KKKK. Therefore, this facility is not subject to this subpart.

Subpart KKKKa, Stationary Combustion Turbines. You are subject to this subpart if you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after December 13, 2024.

The proposed turbines in EUG-20 will have peak heat inputs greater than 10 MMBTUH and will have commenced construction after the applicability date. Therefore, this facility is subject to this subpart. Per Table 1 to Subpart KKKKa of Part 60, Title 40, for a new combustion turbine firing natural gas with a rating over 850 MMBTUH, the NO_x emission standard is 5 ppm at 15% O₂ with a utilization rate >45%, 9 ppm at 15% O₂ with a utilization rate ≤45% and a design efficiency <38%, and 25 ppm at 15% O₂ with a utilization rate ≤45% and a design efficiency ≥38%. The turbines are limited to 2,920 hours per year (33.33% utilization rate) and have a design efficiency of 38.5% based off manufacture's specs, making the baseline for the SCCTs 25 ppm at 15% O₂ (or 0.092 lb-NO_x/MMBtu or 0.83 lb-NO_x/MWh-gross or 0.85 lb-NO_x/MWh-net).

Compliance can be demonstrated by performing annual performance test in accordance with § 60.4400a, if you do not have NO_x CEMS. You must conduct the performance test according to the requirements in § 60.8 and [paragraphs \(b\)](#) through [\(d\)](#) of this subpart's section.

As an alternative, if you use NO_x CEMS, the performance test must be performed according to the procedures specified in [paragraph \(b\)](#) of § 60.4405a.

Additionally, per 40 CFR §60.4330(a)(1) or (a)(2), SO₂ emissions from combustion are limited to 0.9 lb/MWh-gross output (110 ng/J), or the units must not burn any fuel with a total potential sulfur emissions in excess of 0.060 lb SO₂/MMBTU heat input (26 ng SO₂/J). PSO will use natural gas to demonstrate compliance to not exceed 0.060 lb SO₂/MMBTU of sulfur emissions.

Subpart TTTT, Greenhouse Gas Emissions for Electric Generating Units. This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014, but on or before 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 after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected 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).

The existing units at this facility were constructed prior to the applicability dates and have not been modified or reconstructed. The proposed new units will be constructed after the applicability dates. Therefore, this facility is not subject to this subpart.

Subpart TTTTa, Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units. This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from coal-fired steam generating units or integrated gasification combined cycle (IGCC) facilities that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from stationary combustion turbines that commences construction or reconstruction after May 23, 2023. In addition to the applicability dates, affected sources must have a based load rating greater than 260 gigajoules per hour (250 MMBTUH) of fossil fuel (either alone or in combination with any other fuel), and serve a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The existing units at this facility were constructed prior to the applicability dates and have not been modified or reconstructed. The proposed new units will fall within the applicability date and will therefore be subject to this subpart.

Table 1 to Subpart TTTTa of Part 60, Title 40, the CO₂ standards for affected stationary combustion turbines that commenced construction or reconstruction after May 23, 2023, are stated below:

Affected EGU Category	CO ₂ Emission Standard
Base Load Combustion Turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO₂/MWh (800 to 1,250 lb CO₂/MWh) of gross energy output; or 370 to 570 kg CO₂/MWh (820 to 1,280 lb CO₂/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 CO₂/MWh (100 to 150 lb CO₂/MWh) of gross energy output; or 42 to 64 kg CO₂/MWh (97 to 139 lb CO₂/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 .

The proposed new units will be subject to these emission standards as specified in the above table based on the affected EGU category. Per 40 CFR §60.5580a, these categories are defined as the following:

- 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.
- 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.
- 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.

Per 40 CFR §60.5520a(d)(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 CO₂/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.

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 CO₂ emission standard of this subpart shall be determined on a 12-operating-month rolling average basis.

The new units will only burn natural gas, will comply with the applicable emission standard for intermittent combustion turbines, and will demonstrate compliance by keeping fuel purchase records on a 12-month rolling total.

At the time of permit issuance, NSPS Subpart TTTTa is currently under review by EPA. If federal legislation, rulemaking, or a court ruling invalidates all, or part of, TTTTa, the invalidated portions will no longer be applicable through this permit. In the interim, DEQ will exercise enforcement discretion as appropriate.

NESHAP, 40 CFR Part 61

[Not Applicable]

There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides, or vinyl chloride.

NESHAP, 40 CFR Part 63

[Subparts YYYY, ZZZZ, and DDDDD Applicable]

Subpart Q, Industrial Process Cooling Towers. The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources. All facilities operated by PSO have ceased using chrome in cooling water. Therefore, this facility is not subject to this subpart.

Subpart YYYY, Stationary Combustion Turbines. You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions. Since Unit 1A and Unit 1B were constructed before January 14, 2003, they are therefore defined as existing units. Per 40 CFR § 63.6090(b)(4), “Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine...” While this subpart is applicable for those units, there are no applicable compliance requirements for the existing units.

The proposed new units will be constructed after January 14, 2003, and will be subject to this subpart.

For each new or reconstructed stationary combustion turbine you must comply with the following emission limitations and operating limitations:

- For each new or reconstruction stationary combustion turbine which is: a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine, you must meet the following emission limitations: limit the concentration of formaldehyde to 91 ppbvd or less at 15-percent O₂, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in [§ 63.6175](#).

- For each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst, you must maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. You are not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature.
- For each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst, you must maintain any operating limitations approved by the Administrator.

Initial compliance for the emission limit for formaldehyde will be demonstrated if the average formaldehyde concentration meets the emission limit concentration of 91 ppbvd or less at 15-percent O₂.

Continuous compliance for each stationary combustion turbine complying with the emission limitation for formaldehyde with an oxidation catalyst must demonstrate compliance by continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer. For turbines without the use of an oxidation catalyst, compliance must be demonstrated by continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects RICE that are located at a major source and at area sources. The facility is considered a major source and therefore applicable to this subpart. Owners and operators of new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines). No further requirements apply for engines subject to NSPS under this part. A stationary RICE, located at a major source of HAP emissions, is existing if construction commenced prior to June 12, 2006. The existing emergency engines at this facility were constructed prior to June 12, 2006, and have not been reconstructed. A summary of the requirements for the existing emergency CI RICE located at this facility are shown below.

Engine Category	
Remote	Requirements
Emergency stationary CI RICE and black start stationary CI RICE	Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first.
	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; and
	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.

Subpart DDDDD, Industrial, Commercial, and Institutional Boilers and Process Heaters. You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater that is located at, or is part of, a major source of HAP. Except for normal recordkeeping and notification requirements, only work practice standards apply, as found in Items 1 or 3 and 4 of Table 3. These include tune-ups either every five years (equipped with a continuous oxygen trim system) or annually (not equipped with a continuous oxygen trim system) and one-time energy assessments based on a number of inspections, evaluations, reviews, and reports detailed in paragraphs a through h of Item 4.

The two new fuel gas heaters (HTR 1 and HTR 2) will be subject to this rule. The heaters will be fired with natural gas only and thus are not subject to emissions limits under NESHAP DDDDD. The units will be subject to a one-time energy assessment, and ongoing work practices, as specified in the rule. The rule does not require tune ups on natural gas-fired boilers and heaters less than 5 MMBTUH.

Subpart UUUUU, Coal- and Oil-fired Electric Utility Steam Generating Units. You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU. All units are fired with natural gas. Therefore, this facility is not subject to this subpart.

Subpart CCCCCC, Gasoline Dispensing Facilities (GDF). The affected source to which this subpart applies is each GDF that is located at an area source. The affected source includes each gasoline cargo tank during delivery of product to a GDF and also includes each storage tank. The facility is a major source. Therefore, this facility is not subject to this subpart.

Subpart JJJJJ, Industrial, Commercial, and Institutional Boilers. You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of HAP. The facility is a major source of HAP. Therefore, this facility is not subject to this subpart.

CAM, 40 CFR Part 64

[Applicable]

Compliance Assurance Monitoring (CAM applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant;
- It uses a control device to achieve compliance with the applicable emission limit or standard; and
- It has the potential emissions, prior to the control device, of the applicable regulated air pollutant of greater than the major source thresholds.

Of the emission units that are controlled, the new SCCTs will have the potential emissions to reach the applicable regulated air pollutant major source threshold prior to control. CAM will be addressed in the subsequent operating permit application.

Chemical Accident Release Prevention Provisions, 40 CFR 68

[Applicable]

The facility uses commercial natural gas fuel, which is comprised of mainly methane, a listed substance in CAAA 90 Section 112(r). However, this substance is not stored on-site. The small quantity that is in the pipelines on the facility grounds is much less than the 10,000-pound threshold quantity (TQ) and therefore is excluded from all requirements, including the Risk Management Plan (RMP). Chlorine, hydrazine, and ammonal are no longer used or stored on site. There are no hydrogen storage tanks at the facility. However, the facility has permanent compressed hydrogen cylinders and aqueous ammonia tanks. The following table presents a rough estimate of the amount of each material. The RMP was submitted to EPA Region 6 in a timely fashion and assigned EPA ID# 100000011603. More information on this federal program is available on the webpage: www.epa.gov/rmp.

Material	CAS #	Storage Capacity (lb)	TQ (lbs)
Hydrogen	-	689	10,000
Aqueous Ammonia	1336-21-6	1,494	-

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]

Acid Rain renewal Permit No. 2024-0454-ARR5 was issued on March 4, 2025, and will continue as a separate permit.

Acid Rain, 40 CFR Part 73 (SO₂ Requirements) [Applicable]

SO₂ initial allowances as published in 40 CFR § 73.10 are listed in Permit No. 2024-0454-ARR5.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]

Certification testing has been completed for the CEM system required for each unit, and EPA issued an approval certification on February 5, 1997, for Units 1 and 2, and on October 9, 1996, for Unit 3.

Acid Rain, 40 CFR Part 76 (Phase II NO_x Requirements) [Applicable]

NO_x emission limits are set in Permit No. 2024-0454-ARR5 based on Phase II limits commencing January 1, 2008, under 40 CFR § 76.8 for Unit 3. Compliance with the Acid Rain annual NO_x requirements will be according to the averaging plan.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F Applicable]

These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds

under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030. This facility does not utilize any Class I & II substance

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

Federal NO_x and SO₂ Trading Programs, 40 CFR Part 97

[Subpart EEEEE is Applicable]

Subpart EEEEE, Cross-State Air Pollution Rule (CSAPR) NO_x Ozone Season Group 2 Trading Program. This subpart establishes various provisions for the CSAPR NO_x Ozone Season Group 2 Trading Program, under Section 110 of the Clean Air Act and under the Federal Implementation Plan (FIP) codified under 40 CFR § 52.38. Under this subpart, the permittee is required to designate an official representative, monitor emissions, keep records, and make reports in accordance with §§ 97.830 through 97.835. The monitoring program must comply with 40 CFR Part 75 or an alternative monitoring program must be requested and approved. CSAPR NO_x Ozone Season Group 2 allowances are periodically allocated to the facility and at the completion of the allowance transfer deadline for the control period in a given year the permittee is required to hold, in the source's compliance account administered by the EPA Clean Air Markets Division (CAMD), sufficient allowances available for deduction for such control period under § 97.824(a) in an amount not less than the tons of total NO_x emissions for the control period from all CSAPR NO_x Ozone Season Group 2 units at the facility. The control period starts on May 1 of a calendar year, except as provided in § 97.806(c)(3), and ends on September 30 of the same year. For the CSAPR NO_x Ozone Season Group 2 Trading Program, the deadline for obtaining sufficient allowances is midnight of November 1 (if November 1 is a business day) or midnight of the first business day after November 1 (if November 1 is not a business day). Fines and future allowance deductions will be levied as described in § 97.806 if the permittee holds insufficient allowances at the completion of the allowance transfer deadline. The process of establishing an allowance account and requirements for administering an account are included in § 97.820. The recording of allowance allocations is described in § 97.821. Submission and recording of allowance transfers is described in §§ 97.822 and 97.823. Compliance with ozone season emissions limitations and assurance provisions are described in §§ 97.824 and 97.825. Extra allowances may be banked (see § 97.826) and these vintage allowances may be used in later years with certain restrictions. These allowances do not constitute a property right. No Title V permit revision is required for any

allocation, holding, deduction, or transfer of allowances in accordance with this subpart. Unit 1A, Unit 1B, Unit 2, SCCT 5, and SCCT 6 are CSAPR NO_x Ozone Season Group 2 units subject to the requirements of this subpart. The permit includes the requirement to comply with all applicable requirements of this subpart.

Subpart GGGGG, Cross-State Air Pollution Rule (CSAPR) NO_x Ozone Season Group 3 Trading Program. The Good Neighbor Plan does not establish a new emissions trading program, but instead modifies the Group 3 trading program initially established in the Revised CSAPR Update and expands the program to apply to EGUs in the additional states included in the Good Neighbor Plan. The revised Group 3 NO_x Ozone Season limits were supposed to take effect for the time period of August 4, 2023, through September 30, 2023, of the 2023 Ozone Season. However, some courts have issued preliminary orders temporarily staying the effectiveness of EPA's Good Neighbor SIP disapproval action (88 FR 9336) with respect to several states, and EPA is taking measures to comply with those orders.

SECTION XIV. COMPLIANCE

COMPLIANCE AND ENFORCEMENT CASE

The following enforcement cases have been opened or resolved since issuance of the last Part 70 renewal permit, Permit No. 2019-0607-TVR3, issued on August 24, 2022:

On April 15, 2024, a full compliance evaluation was conducted, which resulted in Enforcement Case No. 12870. The evaluation found there was a violation related to the operation requirements outlined in NESHAP UUUUU. Specifically, the facility failed to operate the sorbent trap CMS during the Unit 3 startups. PSO provided a detailed explanation of the event and discussed corrective measures implemented by the facility to prevent recurrence. This enforcement case was closed on June 4, 2024.

On May 22, 2024, PSO submitted a voluntary self-disclosure for this facility which resulted in Enforcement Case No. 12869. The self-disclosure stated there was a violation related to the reporting requirements outlined in NESHAP Subpart UUUUU. Specifically, the facility failed to properly complete mercury monitoring. PSO implemented internal procedures to review and confirm the completion of reporting requirements. This enforcement case was closed on September 5, 2024.

On November 8, 2024, PSO submitted a voluntary self-disclosure for this facility which resulted in Enforcement Case No. 13248. The self-disclosure stated there was a violation related to the Part 70 Permits requirements outlined in OAC 252:100-8. Specifically, the facility failed to submit quarterly EDR per Specific Condition 4b of Permit No. 2019-0607-TVR3. PSO implemented internal procedures to ensure that reports were submitted on time. This enforcement case was closed on December 11, 2024.

There are no active Air Quality compliance or enforcement issues concerning this facility.

INSPECTION

The following periodic inspections have been conducted since issuance of the last Part 70 renewal permit, Permit No. 2019-0607-TVR3, issued on August 23, 2022:

On September 6, 2022, a partial compliance evaluation was conducted on-site by DEQ Enforcement Inspector Matthew Webb. He was accompanied by William Hildeson, Environmental Specialist, and Ken Ruffin, Senior Engineer Air Quality Services, who represented PSO. The reason was for reporting requirements. No deviations were reported.

On April 15, 2024, a full compliance evaluation was conducted on-site by DEQ Enforcement Inspectors Alicia Foster, Sam Luitjens, and Permit Engineer Jennie Doan. They were accompanied by Sammie Miller, Plant Environmental Coordinator, who represented PSO. Based on the information obtained during this evaluation, Enforcement Case No. 12870 was opened. This case was closed on June 4, 2024.

On March 3, 2026, a full compliance evaluation was conducted on-site by DEQ Enforcement Inspector Alicia Foster. Potential violations were noted during the evaluation process, however, DEQ determined that no further actions were required.

FEE PAID

The fee of \$15,000 for three modifications (M-2, M-3, and M-4) to a Part 70 construction permit (\$5,000 per submitted modification) application was paid.

SECTION XV. TIER CLASSIFICATION, PUBLIC AND EPA REVIEW

TIER CLASSIFICATION

This application has been determined to be **Tier II**, based on the request for a Part 70 construction permit modification for an existing major source. The construction permit will be processed under the Traditional process. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

PUBLIC, STATE, AND TRIBAL REVIEW

The applicant has published a “Notice of Filing a Tier II Application” in the *Tulsa World*, a local newspaper in Rogers County on December 23 of 2025. The notice states that the application was available for public review at the facility or the DEQ office in Oklahoma City as well as the Will Rogers Library in Claremore, Oklahoma.

The applicant will publish a “Notice of Tier II Draft Permit”. The notice will state that the drafted permit will be available for public review at a public location in the County or the DEQ office in Oklahoma City. Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page: <https://oklahoma.gov/deq.html>.

This facility is located within 50 miles of the border of Oklahoma-Kansas. The state of Kansas will be notified of the draft permit.

This facility is located in Rogers County. Tribal Nations will be notified of the drafted permit.

SECTION XVI. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues that would prevent issuance of the permit. Issuance of the permit is recommended, contingent on public, state, and tribal review.

DRAFT**APPENDIX A. RBLC Summary Data****RBLC Summary: Simple Cycle Combustion Turbines, Natural Gas, >100 MW – NO_x**

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units
AK-0083	Kenai Nitrogen Operations	1/6/2015	Five (5) Natural Gas Fired Combustion Turbines	37.6	MMBtu/hr	Selective Catalytic Reduction	7	PPMV
AK-0085	Gas Treatment Plant	8/13/2020	Six (6) Simple Cycle Gas-Turbines	386	MMBtu/hr	DLN combustors	15	PPMV @ 15% O ₂
AK-0088	Liquefaction Plant	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	SCR, DLN combustors	2	PPMV @ 15% O ₂
AL-0329	Colbert Combustion Turbine Plant	9/21/2021	Three Simple Cycle Combustion Turbines	229	MW	DLN	9	PPMVD @ 15% O ₂
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Four simple cycle combustion turbines	240	MW	DLN combustors and water injection	9	PPMVD @ 15% O ₂
LA-0316	Cameron LNG Facility	2/17/2017	Gas turbines (9 units)	1069	MMBtu/hr	DLN burners	15	PPMVD @ 15% O ₂
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Simple Cycle Combustion Turbines	927	MMBtu/hr	DLN Combustor Design	9	PPMV
LA-0349	Driftwood LNG Facility	7/10/2018	Compressor Turbines (20)	540	MMBtu/hr	DLN and SCR	5	PPMVD @ 15% O ₂
MI-0420	DTE Gas Company - Milford Compressor Station	6/3/2016	FG-TURBINES	10504	HP	DLN burners	15	PPM
MI-0426	DTE Gas Company – Milford Compressor Station	3/24/2017	FGTURNBINES (5 Simple Cycle CTs)	10504	HP	DLN burners.	15	PPM
TX-0819	Gaines County Power Plant	4/28/2017	Simple Cycle Turbine	227.5	MW	DLN burners, limited operation (2000 hours)	9	PPMVD @ 15% O ₂
TX-0826	Mustang Station	8/16/2017	Simple Cycle Turbine	162.8	MW	Dry Low Nox Burners	9	pmmvd
TX-0975	Freestone Peakers Plant	6/13/2024	Simple cycle gas turbines GE 7FA.05	221	MW	DLNB	9	PPMVD @ 15% O ₂

RBLC Summary: Simple Cycle Combustion Turbines, Natural Gas, >100 MW – CO

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units
AK-0083	Kenai Nitrogen Operations	1/6/2015	Five (5) Natural Gas Fired Combustion Turbines	37.6	MMBtu/hr		50	PPMV @ 15% O ₂
AK-0085	Gas Treatment Plant	8/13/2020	Six (6) Simple Cycle Gas-Turbines	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	15	PPMV @ 15% O ₂
AK-0088	Liquefaction Plant	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	Oxidation Catalyst	5	PPMV @ 15% O ₂
AL-0329	Colbert Combustion Turbine Plant	9/21/2021	Three Simple Cycle Combustion Turbines	229	MW	None listed	9	PPMVD @ 15% O ₂
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Four simple cycle combustion turbines	240	MW	DLN combustors and water injection	9	PPMVD @ 15% O ₂
LA-0307	Magnolia LNG Facility	3/21/2016	Gas Turbines (8 units)	333	MMBtu/hr	good combustion practices and fueled by natural gas	0.062	LB/MM BTU
LA-0316	Cameron LNG Facility	2/17/2017	Gas turbines (9 units)	1069	MMBtu/hr	good combustion practices and fueled by natural gas	15	PPMVD @ 15% O ₂
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MMBtu/hr	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	36	PPMV
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Simple Cycle Combustion Turbines	927	MMBtu/hr	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	25	PPMV
LA-0349	Driftwood LNG Facility	7/10/2018	Compressor Turbines (20)	540	MMBtu/hr	Good Combustion Practices	25	PPMVD @ 15% O ₂
MI-0420	DTE Gas Company -Milford Compressor Station	6/3/2016	FG-TURBINES	10504	HP	Good combustion practices and clean burn fuel	25	PPM
MI-0426	DTE Gas Company - Milford Compressor Station	3/24/2017	FGTURNBINES (5 Simple Cycle CTs)	10504	HP	Good combustion practices and clean burn fuel	25	PPM
TX-0819	Gaines County Power Plant	4/28/2017	Simple Cycle Turbine	227.5	MW	DLN	9	PPMVD @ 15% O ₂
TX-0826	Mustang Station	8/16/2017	Simple Cycle Turbine	162.8	MW	DLN	NA	
TX-0975	Freestone Peakers Plant	6/13/2024	Simple cycle gas turbines	221	MW	good combustion practices.	9	PPMVD @ 15% O ₂

RBLC Summary: Simple Cycle Combustion Turbines, Natural Gas, >100 MW – PM<10

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
AK-0083	Kenai Nitrogen Operations	1/6/2015	Five (5) Natural Gas Fired Combustion Turbines	37.6	MMBtu/hr		0.0074	LB/MMBTU	N/A	N/A
AK-0085	Gas Treatment Plant	8/13/2020	Six (6) Simple Cycle Gas-Turbines	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	N/A	N/A
AK-0088	Liquefaction Plant	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	10	% OPACITY
LA-0307	Magnolia LNG Facility	3/21/2016	Gas Turbines (8 units)	333	MMBtu/hr	good combustion practices and fueled by natural gas	N/A	N/A	N/A	N/A
LA-0316	Cameron LNG Facility	2/17/2017	Gas turbines (9 units)	1069	MMBtu/hr	good combustion practices and fueled by natural gas	0.0076	LB/MMBTU	N/A	N/A
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MMBtu/hr	Good Combustion Practices	4.5	LB/H	N/A	N/A
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Simple Cycle Combustion Turbines	927	MMBtu/hr	Good Combustion Practices	8	LB/H	N/A	N/A
LA-0349	Driftwood LNG Facility	7/10/2018	Compressor Turbines (20)	540	MMBtu/hr	Good Combustion Practices and Use of low sulfur facility fuel gas	0.0066	LB/MMBTU	N/A	N/A
MI-0420	DTE Gas Company – Milford Compressor Station	6/3/2016	FG-TURBINES	10504	HP	Pipeline quality natural gas and good combustion practices.	0.015	LB/MMBTU	N/A	N/A
MI-0426	DTE Gas Company - Milford Compressor Station	3/24/2017	Simple Cycle CTs	10504	HP	Combustion air inlet filter, pipeline quality natural gas and good combustion practices.	0.015	LB/MMBTU	N/A	N/A

RBLC Summary: Simple Cycle Combustion Turbines, Natural Gas, >100 MW – PM<2.5

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
AK-0083	Kenai Nitrogen Operations	1/6/2015	Five (5) Natural Gas Fired Combustion Turbines	37.6	MMBtu/hr		0.0074	LB/MMBTU	N/A	N/A
AK-0085	Gas Treatment Plant	8/13/2020	Six (6) Simple Cycle Gas-Turbines	386	MMBtu/hr	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	N/A	N/A
AK-0088	Liquefaction Plant	7/7/2022	Six Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	10	% OPACITY
AL-0329	Colbert Combustion Turbine Plant	9/21/2021	Three Simple Cycle Combustion Turbines	229	MW	None listed	0.008	LB/MMBTU	18	lb/hr
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Four simple cycle combustion turbines	240	MW	DLN combustors and water injection	0.0031	LB/MMBTU	6.6	lb/hr steady state
LA-0316	Cameron LNG Facility	2/17/2017	Gas turbines (9 units)	1069	MMBtu/hr	Good combustion practices and fueled by natural gas	0.0076	LB/MMBTU	N/A	N/A
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MMBtu/hr	Good Combustion Practices and use of natural gas.	4.5	LB/H	N/A	N/A
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Simple Cycle Combustion Turbines	927	MMBtu/hr	Good Combustion Practices and use of natural gas.	8	LB/H	N/A	N/A
LA-0349	Driftwood LNG Facility	7/10/2018	Compressor Turbines (20)	540	MMBtu/hr	Good Combustion Practices and Use of low sulfur fuel gas	0.0066	LB/MMBTU	N/A	N/A
MI-0420	DTE Gas Company	6/3/2016	FG-TURBINES	10504	HP	Pipeline quality natural gas and good combustion practices.	0.015	LB/MMBTU	N/A	N/A
MI-0426	DTE Gas Company-	3/24/2017	Simple Cycle CTs	10504	HP	Pipeline quality natural gas and good combustion practices.	0.015	LB/MMBTU	N/A	N/A
TX-0819	Gaines County Power Plant	4/28/2017	Simple Cycle Turbine	227.5	MW	Pipeline natural gas, good combustion practices	8.5	TPY	PM10 and 2.5	
TX-0826	Mustang Station	8/16/2017	Simple Cycle Turbine	162.8	MW	pipeline quality natural gas and good combustion practices	27	TPY	PM10 and 2.5	

RBLC Summary: Simple Cycle Combustion Turbines, Natural Gas, >100 MW – CO₂e

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
AK-0083	Kenai Nitrogen Operations	1/6/2015	Natural Gas Fired Combustion Turbines	37.6	MMBtu/hr		59.61	TONS/MMCF	91500	TONS/YEAR
AK-0085	Gas Treatment Plant	8/13/2020	Simple Cycle Gas-Turbines	386	MMBtu/hr	Good combustion practices and clean burning fuel (NG)	117.1	LB/MMBTU	N/A	N/A
AK-0088	Liquefaction Plant	7/7/2022	Simple Cycle Gas-Fired Turbines	1113	MMBtu/hr	Good combustion practices and burning clean fuels (natural gas)	117.1	LB/MMBTU	N/A	N/A
AL-0329	Colbert Combustion Turbine Plant	9/21/2021	Simple Cycle Combustion Turbines	229	MW	None listed	120	LB/MMBTU		
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Simple cycle combustion turbines	240	MW	DLN combustors and water injection	15420	BTU KWH	1899	lb/MW-hr
LA-0307	Magnolia LNG Facility	3/21/2016	Gas Turbines	333	MMBtu/hr	good combustion, operating, and maintenance practices and fueled by natural gas	N/A	N/A	N/A	N/A
LA-0316	Cameron LNG Facility	2/17/2017	Gas turbines	1069	MMBtu/hr	good combustion practices and fueled by natural gas; high thermal efficiency turbines	N/A	N/A	N/A	N/A
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	263	MMBtu/hr	Good operation and maintenance practices and insulation.	134907	T/YR	N/A	N/A
LA-0331	Calcasieu Pass LNG Project	9/21/2018	Simple Cycle Combustion Turbines	927	MMBtu/hr	Good combustion practices	1426146	T/YR	N/A	N/A
LA-0349	Driftwood LNG Facility	7/10/2018	Compressor Turbines	540	MMBtu/hr	Use Low Carbon Fuel, Energy Efficiency Measures, and Good Combustion Practices	N/A	N/A	N/A	N/A
MI-0420	DTE Gas Company -	6/3/2016		10504	HP	Use of pipeline quality natural gas and energy efficiency measures.	196998	T/YR	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
MI-0426	DTE Gas Company -	3/24/2017	5 Simple Cycle CTs	10504	HP	Use of pipeline quality natural gas and energy efficiency measures.	196998	T/YR	N/A	N/A
TX-0819	Gaines County Power Plant	4/28/2017	Simple Cycle Turbine	227.5	MW	pipeline natural gas, good combustion practices	1300	lb/MW-hr	TTTT	
TX-0826	Mustang Station	8/16/2017	Simple Cycle Turbine	162.8	MW	pipeline quality natural gas and good combustion practices.	120	LB/MMBTU		
TX-0975	Freestone Peakers Plant	6/13/2024	Simple cycle gas turbines	221	MW	good combustion practices.	1899	lb/MW-hr base load	TTTTa	

RBLC Summary: Fuel Gas Heater, Natural Gas, NOx

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
IL-0121	Invenergy Nelson Expansion LLC	9/27/2016	Fuel Heater	15	MMBtu/hr		0.033	LB/MMBTU	N/A	N/A
IL-0129	CPV Three Rivers Energy Center	7/30/2018	Fuel Heater	12.8	MMBtu/hr	Low-NOx burners	0.011	LB/MMBTU	N/A	N/A
IL-0130	Jackson Energy Center	12/31/2018	Fuel Heater	13	MMBtu/hr	Low-NOx burners	0.011	LB/MMBTU	N/A	N/A
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Dew Point Heater	20	MMBtu/hr	Low NOx burners	50	LB	0.95	LB
KY-0115	Nucor Steel Gallatin, LLC	4/19/2021	Air Separation Unit Water Bath Vaporizer	14.5	MMBtu/hr, each	Low-NOx burners	50	LB/MMSCF	6.23	TON/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Dryer	1.2	MMBtu/hr	Use of natural gas, good combustion practices and design	0.12	LB/H	0.53	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Ladle Preheaters and Dryers	16	MMBtu/hr	Use of natural gas, good combustion practices and design	1.6	LB/H	7.01	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Shuttle Cars	30	MMBtu/hr	Low NOx burners	2.1	LB/H	9.2	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Preheaters	9.5	MMBtu/hr	Use of natural gas, good combustion practices and design	0.95	LB/H	4.16	T/YR
PA-0310	CPV Fairview Energy Center	9/2/2016	Dew point heater	3.2	MMBtu/hr		0.035	LB/MMBTU	N/A	N/A
PA-0310	CPV Fairview Energy Center	9/2/2016	Dew point heater	13.8	MMBtu/hr		0.011	LB/MMBTU	N/A	N/A
PA-0311	Moxie Freedom Generation Plant	9/1/2015	Fuel Gas Heater	14.6	MMBtu/hr		0.011	LB/MMBTU	0.7	TPY
PA-0316	Renovo Energy Center, LLC	1/26/2018	Water Bath Heater	15	MMBtu/hr		0.01	LB	0.66	TPY
SC-0182	Fiber Industries LLC	10/31/2017	Process Heaters	50, 54, 61	MMBtu/hr	Low NOx burners	0.05	LB/MMBTU	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanneal furnace	22	MMBtu/hr	Low NOx Burners	50	LB/MMSCF	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing heaters)	4.75	MMBtu/hr	Low NOx Burners	50	LB/MMSCF	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
SC-0183	Nucor Steel - Berkeley	5/4/2018	Boilers	15.4	MMBtu/hr	Low NOX Burners	50	LB/MMSCF	N/A	N/A
SC-0205	Scout Motors Inc A Delaware Corporation	10/31/2023	Rooftop Heating Units	0.78 to 2.65	MMBtu/hr	Low-NOx Burner	0.043	LB/MMBTU	N/A	N/A
TX-0728	Peony Chemical Manufacturing Facility	4/1/2015	Ammonia Start-Up Heater	54	MMBtu/hr	Low NOx burners	1.91	LB/H	0.036	LB/MMBTU
TX-0908	Newman Power Station	8/27/2021	LINE HEATER	3.9	MMBtu/hr	Low NOx burner	0.03	LB/MMBTU	N/A	N/A
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	Ultra Low NOx burners	0.8	T/YR	N/A	N/A
VA-0332	Chickahominy Power LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	Low NOx burners	0.011	LBS/MMBTU	0.6	T/YR
WI-0263	Wisconsin Power & Light - Neenah Generating Station	2/15/2016	Natural gas-fired glycol heaters	4.05	MMBtu/hr	Good combustion practices and use natural gas	0.1	LB/MMBTU	N/A	N/A
WI-0264	WPSC - West Marinette	2/15/2016	Natural gas-fired pipeline heater	3.5	MMBtu/hr	Good combustion practices, pipeline quality natural gas	0.1	LB/MMBTU	N/A	N/A
WI-0299	WPL- Riverside Energy Center	8/20/2020	Natural Gas-Fired Space and Unit Heater	15.5	MMBtu/hr	Only use natural gas in each heater.	0.098	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Low-NOx burners	0.049	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Low-NOx burners	0.049	LB/MMBTU	N/A	N/A

RBLC Summary: Fuel Gas Heater, Natural Gas, CO

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
IL-0129	CPV Three Rivers Energy Center	7/30/2018	Fuel Heater	12.8	MMBtu/hr	Good combustion practice	0.08	LB/HR	N/A	N/A
IL-0130	Jackson Energy Center	12/31/2018	Fuel Heater	13	MMBtu/hr	Good combustion practices	0.08	LB/MMBTU	N/A	N/A
IN-0288	Waupaca Foundry, Inc. Plant 5	6/25/2018	Hot Water Heater	33.65	MMBtu/hr		84	LB/MMSCF	N/A	N/A
IN-0382	Duke Energy Indiana, Inc.- Cayuga Generating Station	2/14/2025	Turbine Fuel Heaters	10	MMBtu/hr	Good combustion practices	0.08	LB/MMBTU	N/A	N/A
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Dew Point Heater	20	MMBtu/hr	Good combustion practices	84	LB/MMSCF	1.6	LB
KY-0115	Nucor Steel Gallatin, LLC	4/19/2021	Air Separation Unit Water Bath Vaporizer	14.5	MMBtu/hr, each	Good Combustion and Operating Practices (GCOP) Plan	84	LB/MMSCF	10.46	TON/YR
LA-0306	Topchem Pollock, LLC	12/20/2016	Ammonia Converter Start-up Heater	20	MMBtu/hr	Use of pipeline quality natural gas and good combustion practices	1.96	LB/H	0.12	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Dryer	1.2	MMBtu/hr	Use of natural gas, good combustion practices and design	0.02	LB/H	0.09	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Ladle Preheaters and Dryers	16	MMBtu/hr	Use of natural gas, good combustion practices and design	0.32	LB/H	1.4	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Shuttle Cars	30	MMBtu/hr	Use of natural gas, use of baffle type burners, good combustion practices and design	2.1	LB/H	9.2	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Preheaters	9.5	MMBtu/hr	Use of natural gas, good combustion practices and design	0.19	LB/H	0.83	T/YR
PA-0310	CPV Fairview Energy Center	9/2/2016	Dew point heater	3.2	MMBtu/hr		0.08	LB/MMBTU	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
PA-0310	CPV Fairview Energy Center	9/2/2016	Dew point heater 13.8	13.8	MMBtu/hr		0.08	LB/MMBTU	N/A	N/A
PA-0311	Moxie Freedom Generation Plant	9/1/2015	Fuel Gas Heater	14.6	MMBtu/hr		0.037	LB/MMBTU	2.37	TPY
SC-0182	Fiber Industries LLC	10/31/2017	Process Heaters	50, 54, 61	MMBtu/hr	Use of clean fuel, and Good Combustion Practices	0.04	LB/MMBTU	0.05	LB/MM BTU
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	22	MMBtu/hr	Good Combustion Practices	84	LB/MMSCF	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	4.75	MMBtu/hr	Good Combustion Practices	84	LB/MMSCF	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Pickle Line Equipment	15.4	MMBtu/hr	Good Combustion Practices	84	LB/MMSCF	N/A	N/A
TX-0728	Peony Chemical Manufacturing Facility	4/1/2015	Ammonia Start-Up Heater	54	MMBtu/hr	limited hours of operation	1.96	LB/H	50	PPMVD @ 3% O2
TX-0770	Oriented Strandboard (OSB) Mill	10/23/2015	Furnaces	12	MMBtu/hr	Good operating practices and RTO	6.96	T/YR	N/A	N/A
TX-0889	Sweeny Old Ocean Facilities	8/8/2020	Catalyst Activator Heaters	6	MMBtu/hr	Good combustion practices	0.082	LB/MMBTU	N/A	N/A
TX-0908	Newman Power Station	8/27/2021	LINE HEATER	3.9	MMBtu/hr	Good combustions practices and pipeline natural gas	50	PPMVD	N/A	N/A
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	good combustion practices	2.6	T/YR	N/A	N/A
VA-0332	Chickahominy Power LLC	6/24/2019	Three (3) Fuel Gas Heaters	103	MMCF/YR	good combustion practices	0.037	LB/MMBTU	0.5	LB/HR
WI-0263	Wisconsin Power & Light - Neenah Generating Station	2/15/2016	Natural gas-fired glycol heaters	4.05	MMBtu/hr	Good combustion practices and use natural gas	0.08	LB/MMBTU	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
WI-0264	WPSC - West Marinette	2/15/2016	Natural gas-fired pipeline heater	3.5	MMBtu/hr	Good combustion practices, only fire pipeline quality natural gas	0.08	LB/MMBTU	N/A	N/A
WI-0299	WPL- Riverside Energy Center	8/20/2020	Natural Gas-Fired Space and Unit Heater	15.5	MMBtu/hr	Only combust natural gas in each heater.	0.082	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Only combust pipeline quality natural gas	0.08	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Only combust pipeline quality natural gas	0.08	LB/MMBTU	N/A	N/A
WI-0309	ND Paper Inc-Biron Division	8/25/2020	Natural Gas-Fired Air makeup Units	0.15 & 0.40	MMBtu/hr	Only use natural gas and use good combustion practices.	84	LB/MMCF	N/A	N/A
WI-0314	Wisconsin Public Service Corporation-Weston Plant	3/10/2022	Space and Water Heaters	3	MMBtu/hr	Use of good combustion practices and use of pipeline quality natural gas.	0.084	LB/MMBTU	N/A	N/A

RBLC Summary: Fuel Gas Heater, Natural Gas, Total PM

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
IL-0129	CVP Three Rivers Energy Center	7/30/2018	Fuel Heater	12.8	MMBtu/hr	Good combustion practice	0.0075	LB/MMBTU	N/A	N/A
IL-0130	Jackson Energy Center	12/31/2018	Fuel Heater	13	MMBtu/hr	Good combustion practice	0.0075	LB/MMBTU	N/A	N/A
IN-0382	Duke Energy Indiana, Inc.- Cayuga Generating Station	2/14/2025	Turbine Fuel Heaters	10	MMBtu/hr	Good combustion practices and use of pipeline quality gas	0.0019	LB/MMBTU	N/A	N/A
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Dew Point Heater	20	MMBtu/hr	Good combustion practices and low sulfur fuels	0.0048	LB	0.1	LB
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Dryer	1.2	MMBtu/hr	Use of natural gas, good combustion practices and design	0.004	LB/H	0.02	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Ladle Preheaters and Dryers	16	MMBtu/hr	Use of natural gas, good combustion practices and design	0.05	LB/H	0.22	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Shuttle Cars	30	MMBtu/hr	Use of natural gas, good combustion practices and design	0.3	LB/H	1.31	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Preheaters	9.5	MMBtu/hr	Use of natural gas, good combustion practices and design	0.03	LB/H	0.13	T/YR
PA-0311	Moxie Freedom Generation Plant	9/1/2015	Fuel Gas Heater	14.6	MMBtu/hr		0.007	LB/MMBTU	0.45	TPY
SC-0182	Fiber Industries LLC	10/31/2017	Process Heaters	50, 54, 61	MMBtu/hr	Use of clean fuel, and Good Combustion Practices	0.0076	LB/MMBTU / HEATER	N/A	N/A
SC-0205	Scout Motors Inc A Delaware Corporation - Blythewood Plant	10/31/2023	Rooftop Heating Units	0.78 to 2.65	MMBtu/hr	Good Combustion Practices	0.0005	LB/MMBTU	N/A	N/A
WI-0263	Wisconsin Power & Light - Neenah Generating Station	2/15/2016	Natural gas-fired glycol heaters	4.05	MMBtu/hr	Good combustion practices and use of natural gas	0.008	LB/MMBTU	N/A	N/A
WI-0264	WPSC - West Marinette	2/15/2016	Natural gas-fired pipeline heater	3.5	MMBtu/hr	Good combustion practices and only fire pipeline quality natural gas	0.008	LB/MMBTU	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
WI-0299	WPL- Riverside Energy Center	8/20/2020	Natural Gas-Fired Space and Unit Heater	15.5	MMBtu/hr	Only combust natural gas in each heater.	0.0075	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Only combust pipeline quality natural gas.	0.01	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	only combust pipeline quality natural gas.	0.01	LB/MMBTU	N/A	N/A
WI-0314	Wisconsin Public Service Corporation-Weston Plant	3/10/2022	Space and Water Heaters	3	MMBtu/hr	Use of good combustion practices and use of pipeline quality natural gas.	N/A	N/A	N/A	N/A

RBLC Summary: Fuel Gas Heater, Natural Gas, Total PM<10

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
IL-0121	Invenergy Nelson Expansion LLC	9/27/2016	Fuel Heater	15	MMBtu/hr		0.105	LB/HR	N/A	N/A
IL-0137	Marquis Carbon Capture LLC	6/23/2025	Space Heaters	3.41	MMBtu/hr	Natural gas shall be the only fuel fired in the heaters; good combustion practices	0.0005	LB/MMBTU	N/A	N/A
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Dew Point Heater	20	MMBtu/hr	Good combustion practices and low sulfur fuels	0.0048	LB	0.1	LB
KY-0115	Nucor Steel Gallatin, LLC	4/19/2021	Air Separation Unit Water Bath Vaporizer	14.5	MMBtu/hr, each	Good Combustion and Operating Practices	7.6	LB/MMSCF	0.95	TON/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Dryer	1.2	MMBtu/hr	Use of natural gas, good combustion practices and design	0.004	LB/H	0.02	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Ladle Preheaters and Dryers	16	MMBtu/hr	Use of natural gas, good combustion practices and design	0.05	LB/H	0.22	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Shuttle Cars	30	MMBtu/hr	Use of natural gas, good combustion practices and design	0.3	LB/H	1.31	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Preheaters	9.5	MMBtu/hr	Use of natural gas, good combustion practices and design	0.03	LB/H	0.13	T/YR
PA-0311	Moxie Freedom Generation Plant	9/1/2015	Fuel Gas Heater	14.6	MMBtu/hr		0.007	LB/MMBTU	0.45	TPY
SC-0182	Fiber Industries LLC	10/31/2017	Process Heaters	50, 54, 61	MMBtu/hr	Use of clean fuel, and Good Combustion	0.0076	LB/MM BTU / HEATER	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	22	MMBtu/hr	Good Combustion Practices	7.6	LB/MMSCF	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	4.75	MMBtu/hr	Good combustion practices	7.6	LB/MMSCF	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Pickle Line Equipment	15.4	MMBtu/hr	Good Combustion Practices	7.6	LB/MMSCF	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
SC-0205	Scout Motors Inc A Delaware Corporation - Blythewood Plant	10/31/2023	Rooftop Heating Units	0.78 to 2.65	MMBtu/hr	Good Combustion Practices	0.0005	LB/MMBTU	N/A	N/A
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas	0.5	T/YR	N/A	N/A
VA-0332	Chickahominy Power LLC	6/24/2019	Fuel Gas Heaters	103	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas	0.4	T/YR	N/A	N/A
WI-0263	Wisconsin Power & Light - Neenah Generating Station	2/15/2016	Natural gas-fired glycol heaters	4.05	MMBtu/hr	Good combustion practices and use natural gas	0.008	LB/MMBTU	N/A	N/A
WI-0264	WPSC - West Marinette	2/15/2016	Natural gas-fired pipeline heater	3.5	MMBtu/hr	Good combustion practices and use pipeline quality natural gas	0.008	LB/MMBTU	N/A	N/A
WI-0299	WPL- Riverside Energy Center	8/20/2020	Natural Gas-Fired Space and Unit Heater	15.5	MMBtu/hr	Only combust natural gas in each heater.	0.0075	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Only combust pipeline quality natural gas.	0.01	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	only combust pipeline quality natural gas.	0.01	LB/MMBTU	N/A	N/A
WI-0314	Wisconsin Public Service Corporation- Weston Plant	3/10/2022	Space and Water Heaters	3	MMBtu/hr	Use of good combustion practices and use of pipeline quality natural gas.	N/A	N/A	N/A	N/A

RBLC Summary: Fuel Gas Heater, Natural Gas, Total PM<2.5

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
IL-0121	Invenergy Nelson Expansion LLC	9/27/2016	Fuel Heater	15	MMBtu/hr		0.105	LB/HR	N/A	N/A
IL-0137	Marquis Carbon Capture LLC	6/23/2025	Space Heaters	3.41	MMBtu/hr	Natural gas shall be the only fuel fired in the heaters; good combustion practices	0.0004	LB/MMBTU	N/A	N/A
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Dew Point Heater	20	MMBtu/hr	Good combustion practices and low sulfur fuels	0.0048	LB	0.1	LB
KY-0115	Nucor Steel Gallatin, LLC	4/19/2021	Air Separation Unit Water Bath Vaporizer	14.5	MMBtu/hr, each	Good Combustion and Operating Practices	7.6	LB/MMSCF	0.95	TON/YR
LA-0306	Topchem Pollock, LLC	12/20/2016	Ammonia Converter Start-up Heater Stack	20	MMBtu/hr	Use of pipeline quality natural gas and good combustion practices	0.18	LB/H	0.01	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Dryer	1.2	MMBtu/hr	Use of natural gas, good combustion practices and design	0.004	LB/H	0.02	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Ladle Preheaters and Dryers	16	MMBtu/hr	Use of natural gas, good combustion practices and design	0.05	LB/H	0.22	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Shuttle Cars	30	MMBtu/hr	Use of natural gas, good combustion practices and design	0.3	LB/H	1.31	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Preheaters	9.5	MMBtu/hr	Use of natural gas, good combustion practices and design	0.03	LB/H	0.13	T/YR
PA-0311	Moxie Freedom Generation Plant	9/1/2015	Fuel Gas Heater	14.6	MMBtu/hr		0.007	LB/MMBTU	0.45	TPY
SC-0182	Fiber Industries LLC	10/31/2017	Process Heaters	50, 54, 61	MMBtu/hr	Use of clean fuel, and Good Combustion	0.0076	LB/MM BTU / HEATER	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	22	MMBtu/hr	Good Combustion Practices	7.6	LB/MMSCF	N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	4.75	MMBtu/hr	Good combustion practices	7.6	LB/MMSCF	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Pickle Line Equipment	15.4	MMBtu/hr	Good Combustion Practices	7.6	LB/MMSCF	N/A	N/A
SC-0205	Scout Motors Inc A Delaware Corporation - Blythewood Plant	10/31/2023	Rooftop Heating Units	0.78 to 2.65	MMBtu/hr	Good Combustion Practices	0.0004	LB/MMBTU	N/A	N/A
TX-0728	Peony Chemical Manufacturing Facility	4/1/2015	Ammonia Start-Up Heater	54	MMBtu/hr	use of gaseous fuel	0.4	LB/H	0.03	T/YR
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas	0.5	T/YR	N/A	N/A
VA-0332	Chickahominy Power LLC	6/24/2019	Fuel Gas Heaters	103	MMCF/YR	Good combustion practices and the use of pipeline quality natural gas.	0.5	T/YR (EACH)	N/A	N/A
WI-0263	Wisconsin Power & Light - Neenah Generating Station	2/15/2016	Natural gas-fired glycol heaters	4.05	MMBtu/hr	Good combustion practices and use natural gas	0.008	LB/MMBTU	N/A	N/A
WI-0264	WPSC - West Marinette	2/15/2016	Natural gas-fired pipeline heater	3.5	MMBtu/hr	Good combustion practices, only fire pipeline quality natural gas	0.008	LB/MMBTU	N/A	N/A
WI-0299	WPL- Riverside Energy Center	8/20/2020	Natural Gas-Fired Space and Unit Heater	15.5	MMBtu/hr	Only combust natural gas in each heater.	0.0075	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Only combust pipeline quality natural gas.	0.01	LB/MMBTU	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	only combust pipeline quality natural gas.	0.01	LB/MMBTU	N/A	N/A
WI-0314	Wisconsin Public Service Corporation-Weston Plant	3/10/2022	Space and Water Heaters	3	MMBtu/hr	Use of good combustion practices and use of pipeline quality natural gas.	N/A	N/A	N/A	N/A

RBLC Summary: Fuel Gas Heater, Natural Gas, CO₂e

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
IL-0121	Invenergy Nelson Expansion LLC	9/27/2016	Fuel Heater	15	MMBtu/hr		1836	TPY	N/A	N/A
IL-0129	CPV Three Rivers Energy Center	7/30/2018	Fuel Heater	12.8	MMBtu/hr	Good combustion practice	6600	TON/YR	N/A	N/A
IL-0130	Jackson Energy Center	12/31/2018	Fuel Heater	13	MMBtu/hr	Good combustion practice	6700	TONS/YEAR	N/A	N/A
IL-0137	Marquis Carbon Capture LLC	6/23/2025	Space Heaters	3.41	MMBtu/hr	Natural gas shall be the only fuel fired in the heaters; good combustion practices	117.1	LB/MMBTU	N/A	N/A
IN-0382	Duke Energy Indiana, Inc.-Cayuga Generating Station	2/14/2025	Turbine Fuel Heaters	10	MMBtu/hr	Good combustion practices and use of pipeline quality natural gas	10258	TONS	N/A	N/A
IN-0384	Sycamore Riverside Energy LLC	3/31/2025	Dew Point Heater	20	MMBtu/hr	Good combustion practices and low sulfur fuels	N/A	N/A	N/A	N/A
KY-0115	Nucor Steel Gallatin, LLC	4/19/2021	Air Separation Unit Water Bath Vaporizer	14.5	MMBtu/hr, each	Good Combustion and Operating Practices (GCOP)	15032	TONS/YR	N/A	N/A
LA-0306	Topchem Pollock, LLC	12/20/2016	Ammonia Converter Start-up Heater Stack	20	MMBtu/hr	Use of pipeline quality natural gas and good combustion practices	169	T/YR	N/A	N/A
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Dryer	1.2	MMBtu/hr	Use of natural gas and energy efficient design	140.22	LB/H	614.18	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Ladle Preheaters and Dryers	16	MMBtu/hr	Use of natural gas and energy efficient design	1869.65	LB/H	8189.03	T/YR
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Shuttle Cars	30	MMBtu/hr	Use of natural gas and energy efficient design	3505.59	LB/H	15354.43	T/YR

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
OH-0381	Northstar Bluescope Steel, LLC	9/27/2019	Tundish Preheaters	9.5	MMBtu/hr	Use of natural gas and energy efficient design	1110.1	LB/H	4862.24	T/YR
PA-0311	Moxie Freedom Generation Plant	9/1/2015	Fuel Gas Heater	14.6	MMBtu/hr		7845	TPY	N/A	N/A
SC-0182	Fiber Industries LLC	10/31/2017	Process Heaters	50, 54, 61	MMBtu/hr	Use of clean fuel, and Good Combustion.	84627	TPY / HEATER	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	22	MMBtu/hr	Use of natural gas and efficient combustion technology through good combustion practices.	11404	TPY	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Galvanizing Line Equipment	4.75	MMBtu/hr	Use of natural gas and efficient combustion technology through good combustion practices	4924	TPY	N/A	N/A
SC-0183	Nucor Steel - Berkeley	5/4/2018	Pickle Line Equipment	15.4	MMBtu/hr	Use of natural gas and efficient combustion technology through good combustion practices	15965	TPY	N/A	N/A
SC-0205	Scout Motors Inc A Delaware Corporation - Blythwood Plant	10/31/2023	Rooftop Heating Units	0.78 to 2.65	MMBtu/hr	Use of natural gas, good combustion practices	118	LB CO2E/MMBTU	N/A	N/A
TX-0770	Oriented Strandboard (OSB) Mill	10/23/2015	Furnaces	12	MMBtu/hr	Good combustion operating practices.	18135	T/YR	N/A	N/A
TX-0824	Jackson County Generating Facility	6/30/2017	Natural-Gas-Fired Fuel Gas Heaters	15.9	MMBtu/hr	Natural gas as a low carbon fuel, good operating and maintenance practices, efficient design, and low annual capacity	2818.74	T/YR	N/A	N/A
TX-0889	Sweeny Old Ocean Facilities	8/8/2020	Catalyst Activator Heaters	6	MMBtu/hr	Good combustion practices	0		N/A	N/A
TX-0908	Newman Power Station	8/27/2021	LINE HEATER	3.9	MMBtu/hr	Good combustions practices and properly maintaining the unit	0		N/A	N/A

RBLC ID	Facility	Permit Date	Process	Capacity	Capacity Units	Control	Permitted Limit	Units	Secondary Limit	Units
VA-0328	C4GT, LLC	4/26/2018	Dew Point Heater	140	MMCF/YR	use of natural gas and high efficiency design and operation	8208	T/YR	N/A	N/A
VA-0332	Chickahominy Power LLC	6/24/2019	Fuel Gas Heaters	103	MMCF/YR	use of natural gas and high efficiency design and operation	6261	T/YR	N/A	N/A
WI-0266	Green Bay Packaging, Inc. - Shipping Container Division	9/6/2018	Space heaters	40	MMBtu/hr	Good combustion practices, use only natural gas, equip with Low NOx burners	0		N/A	N/A
WI-0297	Green Bay Packaging-Mill Division	12/10/2019	Natural Gas-Fired Space Heaters	8.5	MMBtu/hr	Only fire natural gas.	90	% AVG THERM EFF	N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Low-NOx burners, only combust pipeline quality natural gas	0		N/A	N/A
WI-0300	Nemadji Trail Energy Center	9/1/2020	Natural Gas-Fired Heater	10	MMBtu/hr	Low-NOx burners, only combust pipeline quality natural gas	0		N/A	N/A
WI-0309	ND Paper Inc-Biron Division	8/25/2020	Natural Gas-Fired Air makeup Units	0.15 & 0.40	MMBtu/hr	Only use natural gas and use good design and combustion practices.	120713	LB CO2E/MMCF	N/A	N/A
WI-0314	Wisconsin Public Service Corporation-Weston Plant	3/10/2022	Space and Water Heaters	3	MMBtu/hr	Use of good combustion practices, use of pipeline quality natural gas	0		N/A	N/A

**PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS**

**Public Service Company of Oklahoma
Northeastern Power Station**

Permit No. 2019-0607-C (M-3) PSD

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on October 30, 2025. The Evaluation Memorandum dated September 24, 2026, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Emission limitations and point of emissions: [OAC 252:100-8-6(a)]

a. EUG-01: Gas Turbines and Heat Recovery Steam Generators (HRSG)

ID#	Description	Serial No.	Rating (MW)	Rating (MMBTUH)	Construction Date
1A	GE MS7001FA	297510	160	1,684	2000
1B	GE MS7001FA	297511	160	1,684	2000

Pollutant	BACT Limit Concentration	Turbine Only		Turbine w/ Duct Burner	
		lb/hr	TPY	lb/hr	TPY
NO _x	15 ppmdv ⁽¹⁾	108	418.0	117.0	457.0
SO ₂	-	1.18	5.19	1.26	5.50
PM _{10/2.5}	-	20.9	81.1	21.9	85.5
VOC	-	0.40	1.49	0.50	1.92
CO	12 ppmdv ⁽¹⁾	51.7	198.0	60.60	237.0
H ₂ SO ₄	-	0.06	0.24	0.06	0.25

⁽¹⁾ NO_x and CO concentrations: parts per million by volume, dry basis, corrected to 15% oxygen, on a three-hour rolling average. These concentrations shall not be exceeded except during periods of start-up, shutdown or maintenance operations. Start-up begins when fuel is supplied to the Gas Turbine and ends when the gas turbine reaches Mode 6 (as directed by the control system), or upon completion of combustion tuning after an outage, after completion of maintenance tuning, or as required by the manufacturer. Shutdown begins when the turbine exits Mode 6 and ends with the termination of fuel flow to the turbine, or with recommencement of start-up. Compliance with this condition shall include recordkeeping to demonstrate actual hours in each of start-up and shutdown modes for each CT.

When monitoring shows emissions in excess of the limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9.

Compliance with these emissions shall be demonstrated by fuel usage. Usage of only commercial-grade natural gas is limited to 14,751,840 MMBTU per year at each combustion turbine and 867,240 MMBTU per year at each HRSG set of duct burners. Sulfur content of the natural gas burned shall not exceed 0.25 gr/100 dscf. Emission calculations shall use the best available source, such as CEMs data, the most recent

stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.) For the purposes of calculating and reporting NO₂ and SO₂ emissions, methods prescribed by 40 CFR Part 75 shall be used.

The turbines in EUG-01 are subject and shall comply with the applicable requirements of NSPS Subpart GG as specified under Specific Conditions No. 10.

b. EUG-02: Grandfathered Steam Generators

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
2	Babcock and Wilcox UP-60	495	4,754	1970

The BACT emission limit is 0.148 lb/MMBTU for CO, 3-hour average. CO compliance shall be demonstrated by Reference Method testing once every four operating quarters, as defined in 40 CFR Part 75. The NO_x emission limits applicable to Unit 2 shall be effective and enforceable on January 1, 2027.

ID#	NO _x Emission Limits ⁽¹⁾
2	0.22 lb/MMBTU, rolling 30-calendar day average
	5,530 TPY

⁽¹⁾ Per SARHA

Emission calculations shall use the best available source, such as CEMs data, the most recent stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.) For the purposes of calculating and reporting NO₂ and SO₂ emissions, methods prescribed by 40 CFR Part 75 shall be used.

c. EUG-Aux 2: Steam Generator

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
Aux 2	Babcock and Wilcox FM 120-136 I.H.	-	276.5	July 2026

Pollutant	lb/hr	TPY
TSP = PM ₁₀	5.53	5.09
SO ₂	0.39	0.36
NO _x	41.48	38.15
CO	81.83	75.28
VOC	1.38	1.27

- i. Annual natural gas consumption shall not exceed limit 508,649 MMBTU/YR (equivalent to a 21% annual capacity factor) for EUG-Aux 2. Compliance shall be demonstrated by recording the amount of natural gas consumed monthly (12-month rolling total).

- ii. Emission calculations shall use the best available source, such as CEMs data, the most recent stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.) For the purposes of calculating and reporting NO₂ and SO₂ emissions, methods prescribed by 40 CFR Part 75 shall be used.
- iii. EUG-Aux 2 is subject and shall comply with the applicable requirements of NSPS Subpart Db as specified under Specific Conditions No. 6.

d. EUG-03 and EUG-Aux 3: Steam Generators

EUG-03 Steam Generator

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
3	Combustion Engineering #4974 SCRR	490	4,775	1974/2015

EUG-Aux 3 Steam Generator

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
Aux 3	Combustion Engineering #3M1004	-	239	1974

Emissions from Auxiliary Boiler 3 (Aux 3) shall be limited to the following:

Pollutant	lb/MMBTU
TSP = PM ₁₀	0.0075
SO ₂	0.0006
NO _x	0.137

Annual natural gas consumption shall not exceed limit 544,346 MMBTU/YR (equivalent to a 26% annual capacity factor) for EUG-Aux 3. Compliance shall be demonstrated by recording the amount of natural gas consumed monthly (12-month rolling total).

For Unit 3 (EUG-03), the CO BACT emission limit is 0.530 lb/MMBTU 3-hour average, demonstrated by Reference Method testing once every four operating quarters, as defined in 40 CFR Part 75.

Unit 3 is subject to and shall comply with all applicable requirements of 40 CFR Part 60 Subpart D as indicated in Specific Condition No. 5. The NSPS Subpart D limits are shown in the following table:

ID#	Pollutant	lb/MMBTU
3	NO _x	0.20

Consistent with the SARHA, the NO_x emission limits applicable to Unit 3 shall be effective and enforceable upon US EPA proposed approval of the Oklahoma SIP amendment that contains the SARHA, and not before January 1, 2026:

ID#	Pollutant	TPY
3	NO _x	300.0

Emission calculations shall use the best available source, such as CEMs data, the most recent stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.) For the purposes of calculating and reporting NO₂ and SO₂ emissions, methods prescribed by 40 CFR Part 75 shall be used.

e. EUG-16: Emergency Engines

ID#	Description	Fuel Type	Function	Rating (HP)	Construction Date
GEN 1/2	General Motors, Model MP45A (Electro-Motive Division MU-Type Power Plant)	Diesel	Service at Units 1 and 2	3,600	1968
GEN 3	Detroit Diesel Allison, Model 16V-149T (Supplied by United Engines, Inc., descriptor B/M 6571/6572 M-22C)	Diesel	Service at Unit 3	1,476	1979

- i. The permittee shall comply with all applicable requirements of the NESHAP for Stationary Reciprocating Internal Combustion Engines, Subpart ZZZZ, including but not limited to:
1. § 63.6580 What is the purpose of subpart ZZZZ?
 2. § 63.6585 Am I subject to this subpart?
 3. § 63.6590 What parts of my plant does this subpart cover?
 4. § 63.6595 When do I have to comply with this subpart?
 5. § 63.6603 What emissions limitations must I meet if I own or operate a stationary RICE located at an area source of HAP emissions?
 6. § 63.6605 What are my general requirements for complying with this subpart?
 7. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE located at an area source of HAP emissions?
 8. § 63.6615 When must I conduct subsequent performance tests?
 9. § 63.6620 What performance tests and other procedures must I use?
 10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
 11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
 12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
 13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
 14. § 63.6645 What notifications must I submit and when?
 15. § 63.6650 What reports must I submit and when?

16. § 63.6655 What records must I keep?
 17. § 63.6660 In what form and how long must I keep my records?
 18. § 63.6675 What definitions apply to this subpart?

- ii. The engine shall be fueled with diesel with a maximum sulfur content of 0.0015% by weight.
- iii. The operating hours for each emergency engine shall be limited to 100 hours per year for maintenance, testing, emergency demand response, and deviation of voltage or frequency of 5% or greater from standard voltage or frequency.
- iv. There is no time limit on the use of emergency stationary RICE in emergency situations.
- v. Emission calculations shall use emission factors from AP-42 (1/96), Section 3.4, Table 3.4-1 for large stationary diesel engines.

f. EUG-Chem Store: Stored Chemicals

There are no specific emission limitations for the following emission units:

Material	CAS #	Quantity (lb)	Use
Hydrogen	-	689	Generator heat-exchanger control
Aqueous Ammonia	1336-21-6	1,494	Control of boiler water pH

g. EUG-20: SCCT

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
SCCT 5	GE Vernova	229	2,290	1/1/2027
SCCT 6	GE Vernova	229	2,290	1/1/2027

- i. Emissions for the turbines listed in EUG-20 (SCCT 5 and SCCT 6) shall be limited to the following during normal operations:

Pollutant	BACT Limit (ppm at 15% O ₂)	BACT Limit (lb/MMBTU)	SCCT 5		SCCT 6	
			lb/hr	TPY	lb/hr	TPY
NO _x	9	-	78.46	108.48 ⁽¹⁾	78.46	108.48 ⁽¹⁾
CO	9	-	35.67	49.31 ⁽¹⁾	35.67	49.31 ⁽¹⁾
VOC	-	-	3.47	4.79 ⁽¹⁾	3.47	4.79 ⁽¹⁾
SO ₂	-	-	3.14	4.59	3.14	4.59
PM _{10/2.5}	-	0.0031	7.00	10.23	7.00	10.23
H ₂ SO ₄	-	-	0.24	0.35	0.24	0.35
GHG	-	124.13	281,903.04	411,578.44	281,903.04	411,578.44

⁽¹⁾ Does not include emissions from Start up and Shut down operations.

- ii. The turbines listed in EUG-20 (SCCT 5 and SCCT 6) shall only combust pipeline natural gas as defined in Specific Condition No. 2.
- iii. The turbines listed in EUG-20 (SCCT 5 and SCCT 6) are subject and shall comply with the applicable requirements of NSPS Subpart KKKKa, TTTTa, and NESHAP Subpart YYYY as specified under Specific Conditions No. 11, 12, and 14 respectively.
- iv. The turbines listed in EUG-20 (SCCT 5 and SCCT 6) shall be equipped with dry low-NO_x burners.
- v. For Startup and Shutdown Operations:
 - 1. "Startup" is defined as the period beginning with the first fire of natural gas in the combustion turbine until the unit is operating at a continuous and stable operating level (normal operating mode), the unit reaches dry low NO_x mode (pre-mix mode) and are fully operational and controlling emissions).
 - 2. "Shutdown" is defined as the period beginning when the turbine output is lowered with the intent to shutdown (the unit is no longer in steady state operating mode) and the DLN are not operational and ends with the termination of fuel flow.
 - 3. During Startup and Shutdown Operations, the following alternate short term emission limits apply for each turbine (SCCT 5 and SCCT 6):

Pollutant	18-minutes Startup Uncontrolled (lb/event)	13-minutes Shutdown Uncontrolled (lb/event)
NO _x	57.8	31.9
CO	396.7	252.7

- 4. Compliance with the NO_x and CO Startup and Shutdown limits shall be demonstrated by calculating the total NO_x and CO during the event using CEMS data and comparing it to the limits listed above.
- vi. The permittee shall keep records of the operational status (startup, shutdown, and normal operation) and number of operational status events for each unit.
- vii. Annual natural gas consumption shall not exceed limit 6,685,619.5 MMBTU/YR (equivalent to a 33.33% annual capacity factor) for each turbine (SCCT 5 and SCCT 6). Compliance shall be demonstrated by recording the amount of natural gas consumed monthly (12-month rolling total).
- viii. Emission calculations shall use the best available source, such as CEMs data, the most recent stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.) For the purposes of calculating and reporting NO₂ and SO₂ emissions, methods prescribed by 40 CFR Part 75 shall be used.
- ix. Total emissions shall be limited to the following:

Total EUG-20 Emissions (Including SUSD Operations)

Point Source	NO_x	CO	VOC	SO₂	PM_{10/2.5}	H₂SO₄	GHG	HAP
	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY
SCCT 5	121.94	146.73	14.96	4.59	10.23	0.35	411,578	1.85

SCCT 6	121.94	146.73	14.96	4.59	10.23	0.35	411,578	1.85
Totals	243.88	293.46	29.92	9.18	20.46	0.70	823,156	3.64

h. EUG-21: HTR

ID#	Description	Rating (MMBTUH)	Construction Date
HTR 1	Fuel Gas Heater	2.5	1/1/2027
HTR 2	Fuel Gas Heater	2.5	1/1/2027

- i. Emissions for the heaters listed in EUG-21 (HTR 1 and HTR 2) shall be limited to the following:

ID#	BACT NO _x lb/MMBTU	BACT CO lb/MMBTU	BACT PM _{10/2.5} lb/MMBTU	BACT GHG lb/MMBTU
HTR 1	0.011	0.0745	0.0081	117.65
HTR 2				

ID#	Rating MMBTUH	NO _x TPY	CO TPY	VOC TPY	SO ₂ TPY	PM _{10/2.5} TPY	GHG TPY
HTR 1	2.5	0.04	0.27	0.05	<0.01	0.03	429.41
HTR 2	2.5	0.04	0.27	0.05	<0.01	0.03	429.41

- ii. Annual natural gas consumption shall not exceed limit 7,300 MMBTU/YR (equivalent to a 33.33% annual capacity factor) for each heater (HTR 1 and HTR 2). Compliance shall be demonstrated by recording the amount of natural gas consumed monthly (12-month rolling total).
- iii. Emission calculations shall use the best available source, such as CEMs data, the most recent stack testing results, AP-42 emission factors, or other approved emission factors (such as EPRI, etc.) For the purposes of calculating and reporting NO₂ and SO₂ emissions, methods prescribed by 40 CFR Part 75 shall be used.
- iv. The heaters listed in EUG-21 (HTR 1 and HTR 2) are subject and shall comply with the applicable requirements of NESHAP Subpart DDDDD as specified under Specific Conditions No. 15.
2. All limits in Specific Condition 1 apply to EUG-02 while operating 100% on natural gas (5 gr S/100 SCF). Upon completion of project 1 of Permit No. 2019-0607-C (M-1), Unit 3 (EUG-03) shall only operate utilizing pipeline natural gas. For Unit 1A and 1B (EUG-01), the sulfur content of the natural gas burned shall not exceed 0.25 gr/100 dscf. For EUG-Aux 3, the sulfur content of the natural gas burned shall not exceed 0.20 gr/100dscf. All new fuel-burning equipment (EUG-Aux 2, EUG-03, EUG-20, and EUG-21) shall use pipeline natural gas as defined in 40 CFR Part 72 (0.5 gr S/100 SCF) to ensure compliance with Subchapter 31. The emergency engines listed in EUG-16 shall be fueled with diesel fuel with a sulfur content of 0.0015% by weight or less. For pipeline natural gas, compliance can be shown with a current gas company bill. For diesel fuel, compliance can be shown with a supplier's

latest delivery ticket(s). Compliance shall be demonstrated at least once every calendar year.
[OAC 252:100-31]

3. The facility shall be authorized to operate continuously (24 hours per day, every day of the year).
[OAC 252:100-8-6(a)]
4. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements as listed in renewal Permit No. 2019-0782-ARR4, including the following:
[40 CFR Part 75]
 - a. Compliance with the SO₂ allowances.
 - b. Report quarterly emissions to EPA per 40 CFR Part 75.
 - c. Conduct RATA tests per 40 CFR Part 75.
 - d. Update QA/QC plan for maintenance of the CEMS.
5. The permittee shall comply with all applicable requirements of the NSPS for Fossil-Fuel-Fired Steam Generators, Subpart D, including but not limited to:
[40 CFR Part 60, Subpart D]
 - a. § 60.40 Applicability and designation of affected facility.
 - b. § 60.41 Definitions.
 - c. § 60.44 Standard for nitrogen oxides (NO_x).
 - i. Nitrogen Oxides emissions shall not exceed 0.20 lb/MMBTU for gaseous fossil fuel.
 - d. § 60.45 Emissions and fuel monitoring.
 - i. Monitoring criteria include the operation of continuous monitoring systems for nitrogen oxides, and either oxygen or carbon dioxide.
 - ii. Compliance for sulfur dioxide emissions is based on fuel records.
 - e. § 60.46 Test methods and procedures.
 - i. Test methods are described in detail in 40 CFR § 60.46, including Reference Methods to be used, general requirements per 40 CFR § 60.8, and factors to be used in calculations.
 - ii. The CEMS installed to demonstrate compliance with 40 CFR Part 75 may be used to satisfy (c)(i) of this Specific Condition.
6. The permittee shall comply with all applicable requirements of the NSPS for Industrial-Commercial-Institutional Steam Generators, Subpart Db, including but not limited to:
[40 CFR Part 60, Subpart Db]
 - a. § 60.40b Applicability and delegation of authority.
 - b. § 60.41b Definitions.

- c. § 60.42b Standard for sulfur dioxide (SO₂).
 - d. § 60.43b Standard for particulate matter (PM).
 - e. § 60.44b Standard for nitrogen oxides (NO₂).
 - f. § 60.45b Compliance and performance test methods and procedures for sulfur dioxide.
 - g. § 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.
 - h. § 60.47b Emission monitoring for sulfur dioxide.
 - i. § 60.48b Emission monitoring for particulate matter and nitrogen oxides.
 - j. § 60.49b Reporting and recordkeeping requirements.
7. The permittee shall comply with all applicable requirements of the NSPS for Small Industrial-Commercial-Institutional Steam Generators, Subpart Dc, including but not limited to: [40 CFR Part 60, Subpart Dc]
- a. § 60.40c Applicability and delegation of authority.
 - b. § 60.41c Definitions.
 - c. § 60.42c Standard for sulfur dioxide (SO₂).
 - d. § 60.43c Standard for particulate matter (PM).
 - e. § 60.44c Compliance and performance test methods and procedures for sulfur dioxide.
 - f. § 60.45c Compliance and performance test methods and procedures for particulate matter.
 - g. § 60.46c Emission monitoring for sulfur dioxide.
 - h. § 60.47c Emission monitoring for particulate matter.
 - i. § 60.48c Reporting and recordkeeping requirements.
8. The permittee shall operate all fuel-burning equipment to minimize emissions of VOC. Among other things, such operation shall assure, based on manufacturer's data and good engineering practice, that the equipment is not overloaded; that it is properly cleaned, operated, and maintained; and that temperature and available air are sufficient to provide essentially complete combustion. [OAC 252:100-37-36]
9. The permittee shall not replace the modified burners on Unit 2, or the low-NO_x concentric firing systems of Unit 3, unless the new equipment meets or exceeds the current permitted NO_x emissions limits. [OAC 252:100-43]
10. The permittee shall comply with all applicable requirements of the NSPS for Stationary Gas Turbines, Subpart GG, including but not limited to: [40 CFR Part 60, Subpart GG]
- a. § 60.330 Applicability and designation of affected facility.
 - b. § 60.331 Definitions.
 - c. § 60.332 Standard for nitrogen oxides.
 - d. § 60.333 Standard for sulfur dioxide.
 - e. § 60.334 Monitoring of operations.
 - f. § 60.335 Test methods and procedures.

11. The permittee shall comply with all applicable requirements of the NSPS for Stationary Combustion Turbines, Subpart KKKKa, including but not limited to:
[40 CFR Part 60, Subpart KKKKa]
- a. § 60.4300a What is the purpose of this subpart?
 - b. § 60.4305a Does this subpart apply to my stationary combustion turbine?
 - c. § 60.4310a What stationary combustion turbines are not subject to this subpart?
 - d. § 60.4315a What pollutants are regulated by this subpart?
 - e. § 60.4320a What NO_x emissions standard must I meet?
 - f. § 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)?
 - g. § 60.4330a What SO₂ emissions standard must I meet?
 - h. § 60.4331a What are the requirements for operating a stationary temporary combustion turbine?
 - i. § 60.4333a What are my general requirements for complying with this subpart?
 - j. § 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?
 - k. § 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?
 - l. § 60.4342a How do I monitor NO_x control operating parameters?
 - m. § 60.4345a How do I demonstrate compliance with my NO_x emissions standard using a NO_x CEMS?
 - n. § 60.4350a How do I use the NO_x CEMS data to determine excess emissions?
 - o. § 60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?
 - p. § 60.4370a How frequently must I determine the fuel sulfur content?
 - q. § 60.4372a How can I demonstrate compliance with my SO₂ emissions standard using records of the fuel sulfur content?
 - r. § 60.4374a How do I demonstrate compliance with my SO₂ emissions standard and determine excess emissions using a SO₂ CEMS?
 - s. § 60.4375a What reports must I submit?
 - t. § 60.4380a How are NO_x excess emissions and monitor downtime reported?
 - u. § 60.4385a How are SO₂ excess emissions and monitor downtime reported?
 - v. § 60.4390a What records must I maintain?
 - w. § 60.4395a When must I submit my reports?
 - x. § 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?
 - y. § 60.4405a How do I conduct a performance test if I use a NO_x CEMS?
 - z. § 60.4415a How do I conduct performance tests to demonstrate compliance with my SO₂ emissions standard?
 - aa. § 60.4416a What parts of the general
 - bb. provisions apply to my affected EGU?
 - cc. § 60.4417a Who implements and enforces this subpart?
 - dd. § 60.4420a What definitions apply to this subpart?

12. The permittee shall comply with all applicable requirements of the NSPS for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, Subpart TTTTa, including but not limited to: [40 CFR Part 60, TTTTa]
- a. § 60.5508a What is the purpose of this subpart?
 - b. § 60.5509a Am I subject to this subpart?
 - c. § 60.5515a Which pollutants are regulated by this subpart?
 - d. § 60.5520a What CO₂ emissions standard must I meet?
 - e. § 60.5525a What are my general requirements for complying with this subpart?
 - f. § 60.5535a How do I monitor and collect data to demonstrate compliance?
 - g. § 60.5540a How do I demonstrate compliance with my CO₂ emissions standard and determine excess emissions?
 - h. § 60.5550a What notifications must I submit and when?
 - i. § 60.5555a What reports must I submit and when?
 - j. § 60.5560a What records must I maintain?
 - k. § 60.5565a In what form and how long must I keep my records?
 - l. § 60.5570a What parts of the general provisions apply to my affected EGU?
 - m. § 60.5575a Who implements and enforces this subpart?
 - n. § 60.5580a What definitions apply to this subpart?
13. At the time of permit issuance, NSPS Subpart TTTTa is currently under review by EPA. If federal legislation, rulemaking, or a court ruling invalidates all, or part of, TTTTa, the invalidated portions will no longer be applicable through this permit. In the interim, DEQ will exercise enforcement discretion as appropriate.
14. The permittee shall comply with all applicable requirements of the NESHAP for Stationary Combustion Turbines, Subpart YYYY, including but not limited to: [40 CFR Part 63, Subpart YYYY]
- a. § 63.6080 What is the purpose of subpart YYYY?
 - b. § 63.6085 Am I subject to this subpart?
 - c. § 63.6090 What parts of my plant does this subpart cover?
 - d. § 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?
 - e. § 63.6095 When do I have to comply with this subpart?
 - f. § 63.6100 What emission and operating limitations must I meet?
 - g. § 63.6105 What are my general requirements for complying with this subpart?
 - h. § 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
 - i. § 63.6115 When must I conduct subsequent performance tests?
 - j. § 63.6120 What performance tests and other procedures must I use?
 - k. § 63.6125 What are my monitor installation, operation, and maintenance requirements?
 - l. § 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?
 - m. § 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

- n. § 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?
 - o. § 63.6145 What notifications must I submit and when?
 - p. § 63.6150 What reports must I submit and when?
 - q. § 63.6155 What records must I keep?
 - r. § 63.6160 In what form and how long must I keep my records?
 - s. § 63.6165 What parts of the General Provisions apply to me?
 - t. § 63.6170 Who implements and enforces this subpart?
 - u. § 63.6175 What definitions apply to this subpart?
15. The permittee shall comply with all applicable requirements of the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, Subpart DDDDD, including but not limited to: [40 CFR Part 63, Subpart DDDDD]
- a. § 63.7480 What is the purpose of this subpart?
 - b. § 63.7485 Am I subject to this subpart?
 - c. § 63.7490 What is the affected source of this subpart?
 - d. § 63.7491 Are any boilers or process heaters not subject to this subpart?
 - e. § 63.7495 When do I have to comply with this subpart?
 - f. § 63.7499 What are the subcategories of boilers and process heaters?
 - g. § 63.7500 What emission limitations, work practice standards, and operating limits must I meet?
 - h. § 63.7505 What are my general requirements for complying with this subpart?
 - i. § 63.7510 What are my initial compliance requirements and by what date must I conduct them?
 - j. § 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?
 - k. § 63.7545 What notifications must I submit and when?
 - l. § 63.7550 What reports must I submit and when?
 - m. § 63.7555 What records must I keep?
 - n. § 63.7560 In what form and how long must I keep my records?
 - o. § 63.7565 What parts of the General Provisions apply to me?
 - p. § 63.7570 Who implements and enforces this subpart?
 - q. § 63.7575 What definitions apply to this subpart?
16. Unit 1A, Unit 1B, Unit 2, SCCT 5, and SCCT 6 are subject to the Cross-State Air Pollution Rule (CSAPR) NO_x Ozone Season Group 2 Trading Program 40 CFR Part 97, Subpart EEEEE. The permittee shall comply with all applicable requirements, including but not limited to: [40 CFR § 97.801 to § 97.835]
- a. § 97.801 Purpose.
 - b. § 97.802 Definitions.
 - c. § 97.803 Measurements, abbreviations, and acronyms.
 - d. § 97.804 Applicability.
 - e. § 97.805 Retired unit exemption.
 - f. § 97.806 Standard requirements.

- g. § 97.807 Computation of time.
 - h. § 97.808 Administrative appeal procedures.
 - i. § 97.810 State NO_x Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.
 - j. § 97.811 Timing requirements for CSAPR NO_x Ozone Season Group 2 allowance allocations.
 - k. § 97.812 CSAPR NO_x Ozone Season Group 2 allowance allocations to new units.
 - l. § 97.813 Authorization of designated representative and alternate designated representative.
 - m. § 97.814 Responsibilities of designated representative and alternate designated representative.
 - n. § 97.815 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
 - o. § 97.816 Certificate of representation.
 - p. § 97.817 Objections concerning designated representative and alternate designated representative.
 - q. § 97.818 Delegation by designated representative and alternate designated representative.
 - r. § 97.820 Establishment of compliance accounts, assurance accounts, and general accounts.
 - s. § 97.821 Recordation of CSAPR NO_x Ozone Season Group 2 allowance allocations and auction results.
 - t. § 97.822 Submission of CSAPR NO_x Ozone Season Group 2 allowance transfers.
 - u. § 97.823 Recordation of CSAPR NO_x Ozone Season Group 2 allowance transfers.
 - v. § 97.824 Compliance with CSAPR NO_x Ozone Season Group 2 emissions limitation.
 - w. § 97.825 Compliance with CSAPR NO_x Ozone Season Group 2 assurance provisions.
 - x. § 97.826 Banking.
 - y. § 97.827 Account error.
 - z. § 97.828 Administrator's action on submissions.
 - aa. § 97.830 General monitoring, recordkeeping, and reporting requirements.
 - bb. § 97.831 Initial monitoring system certification and recertification procedures.
 - cc. § 97.832 Monitoring system out-of-control periods.
 - dd. § 97.833 Notifications concerning monitoring.
 - ee. § 97.834 Recordkeeping and reporting.
 - ff. § 97.835 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.
17. The permittee shall conduct the following testing as indicated below when operating under representative conditions. Testing shall be conducted using the approved reference methods listed below. [OAC 252:100-8-6(a)(3)(A) & OAC 252-100-43]
- a. Periodic testing of the listed emission units for the specified pollutant shall be conducted at least once during the specified frequency starting from the issuance date of this permit:

Periodic Testing Schedule

ID#	Pollutant	Periodic Testing
Unit 1A (Turbine)	CO	Yes – Every Five Years
Unit 1B (Turbine)	CO	Yes – Every Five Years
Unit 2	CO	Yes – Every Five Years
Unit 3	CO	Yes – Every Year
Aux 2	CO	Yes – Every Five Years

- b. The following referenced methods specified in 40 CFR Part 60 shall be used:
- i. Method 1: Sample and Velocity Traverses for Stationary Sources.
 - ii. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
 - iii. Method 3: Gas Analysis for CO₂, Excess Air, and Dry Molecular Weight.
 - iv. Method 4: Determination of Moisture in Stack Gases.
 - v. Method 10: Determination of CO Emissions from Stationary Sources.
- c. Performance testing shall be conducted while the units are operating under representative conditions.
- d. A protocol describing the testing plan shall be submitted to the Air Quality Division at least 30 days prior to the testing.
- e. A written report documenting the results of emissions testing shall be submitted within 60 days of completion of on-site testing.
18. The permittee shall equip the following units with Continuous Emissions Monitoring System (CEMS) for determining and recording the specified pollutant emissions.

ID#	Pollutant
Unit 1A (Turbine)	NO _x
Unit 1B (Turbine)	NO _x
Unit 2	NO _x
Unit 3	NO _x
SCCT 5	NO _x
	CO
SCCT 6	NO _x
	CO

- a. The NO_x CEMS shall comply with the specifications stated in 40 CFR Part 60 Performance Specification 2 of Appendix B and Procedure 1 of Appendix F.
- b. The CO CEMS shall comply with the specifications stated in 40 CFR Part 60 Performance Specification 4A of Appendix B and Procedure 1 of Appendix F.

19. The permittee shall keep records of operations as listed below. These records shall be maintained on site and accessible to regulatory personnel upon request. Required records shall be retained for a period of at least five years following dates of recording.
[OAC 252:100-43]
- a. Total usage of each type of fuel for each boiler (monthly and cumulative 12-month rolling).
 - b. Emissions data as required by the Acid Rain Program.
 - c. RATA test results from periodic CEMS certification tests.
 - d. Operating hours each CT spends in start-up and in shutdown, as required under Specific Condition No. 1(a) for EUG-01.
 - e. Number of events and duration as required under Specific Condition No. 1(g)(vi) for EUG-20.
 - f. Records demonstrating compliance with Specific Condition No. 1 and 2.
 - g. Operating hours of each emergency generator (monthly and 12-month rolling total).
 - h. Unit 3 NO_x TPY emissions (monthly and 12-month rolling total), as required by Specific Condition No. 1(d).
 - i. Unit 2 NO_x lb/MMBTU (30-day average) and TPY (monthly and 12-month rolling total), as required by Specific Condition No. 1(b).
 - j. Stack testing results as required under Specific Condition No. 1.
 - k. Records as required by 40 CFR Part 60, Subparts D, Db, Dc, GG, KKKKa, and TTTTa.
 - l. Records as required by 40 CFR Part 63, Subparts YYYY, ZZZZ, and DDDDD.
 - m. Records as required by 40 CFR Part 97, Subpart EEEEE.
20. The permittee shall keep records of the following to verify insignificant activities.
[OAC 252:100-43]
- a. Throughput for fuel storage/dispensing equipment operated solely for facility owned vehicles, if throughput is less than 2,175 gallons per day, averaged over a 30-day period (annual total).
 - b. Capacity of all storage tanks with a capacity of 39,894 gallons or less storing a fluid with a true vapor pressure less than 1.5 psia (for each delivery of fluid, the type and quantity).
 - c. Records for any other activity, demonstrating that emissions are less than 5 TPY, unless defined as Trivial as listed in OAC 252:100 Appendix J.
 - d. Vapor pressure of the drip in the Unit 1 and 2 Gas Yard's Condensate Drip Tank
21. The boilers in EUG 2 and 3 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P. The permittee shall comply with all applicable requirements including, but not limited to, the following.
[40 CFR §§ 51.300-309 & Part 51, Appendix Y]
- a. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements.

ID#	Description	Rating (MW)	Rating (MMBTUH)	Construction Date
2	Babcock and Wilcox UP-60	495	4,754	1970
3	Combustion Engineering #4974 SCRR	490	4,775	1974/2015

- b. The permittee shall maintain the Low-NO_x burners and overfire air and shall establish procedures to ensure the controls are properly operated and maintained.
- c. The emission limits below are consistent with the US EPA Regional Haze presumptive limits for BART. The emissions shall not exceed the following emission limits.

ID#	NO _x Emission Limit	Averaging Period
2	0.22 lb/MMBTUH	30-day rolling
3	0.15 lb/MMBTU	30-day rolling
	300 TPY	12-month rolling

ID#	PM ₁₀ Emission Limit	Averaging Period	Combined Annual Emission Rate
3	0.0075 lb/MMBTUH	3-hour	31.17 TPY (12-month rolling)

ID#	SO ₂ Emission Limit	Averaging Period	Annual Emission Rate
3	0.0006 lb/MMBTUH	3-hour	2.47 TPY (12-month rolling)
	3.274 lb/hr		

- d. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.
22. The SARHA will require that beginning in calendar year 2023, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW times 8760 hours) for Unit 3 the operating coal-fired generating unit at Northeastern Station will be reduced as follows:
- to no more than 60 percent in calendar years 2023 and 2024;
 - to no more than 50 percent in calendar years 2025; and
 - to no more than 20 percent in calendar year 2026 and beyond to comply with the 300 TPY limit after ceasing coal combustion (based on rated capacity of 420 MW using natural gas).
23. No later than 30 days after each anniversary date of the issuance of the original Title V permit (June 30, 1999), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6(c)(5)(A) & (D)]
24. This facility is considered an existing Prevention of Significant Deterioration (PSD) facility. As such, the facility is subject to the provisions of OAC 252:100-8-36.2(c) when using projected actual emissions (PAE) for any project as defined therein. [OAC 252:100-8-36.2(c)]

25. The permittee shall submit an application for modification of the Part 70 operating permit within 180 days of commencement of operation of any emission source whose construction has been authorized by this permit. [OAC 252:100-8-6]

**MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(October 16, 2025)**

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.

[40 CFR §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. 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 in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements. [OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F. [OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6(a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

- (1) the date, place and time of sampling or measurement;
- (2) the date or dates analyses were performed;
- (3) the company or entity which performed the analyses;
- (4) the analytical techniques or methods used;
- (5) the results of such analyses; and
- (6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report.

[OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions.

[OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

[OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. Any Excess Emission Report submitted in accordance with this permit shall be certified by a responsible official or designee. This certification shall be signed by a responsible official (or designee, if allowed), and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards (NSPS) under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 CFR §§60.7 and 63.10, 40 CFR Part 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM₁₀). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Parts 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification.

[OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit.

[OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit.

[OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. The term of an Initial Title V or Title V renewal operating permit shall be five years from the date of issuance. Modifications to a Title V or Title V renewal permit does not reset the five year term. The expiration date of all permit actions is specified on the Part 70 permit authorization page.

[OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration.

[OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced.

[OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation.

[OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.

[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued.

[OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

- (1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
- (2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
- (3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
- (4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d).

[OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited.

[OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

- (1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
- (2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
- (3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
- (4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6(a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance.

[OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by

improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. Qualification for consideration of mitigating factors shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

[OAC 252:100-8-6(e)(2)]

- (1)an emergency occurred and the permittee can identify the cause or causes of the emergency;
- (2)the permitted facility was at the time being properly operated;
- (3)during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.

[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

- (1)5 tons per year of any one criteria pollutant.
- (2)2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

- (1) result in no net emissions increases,
- (2) are not modifications under any provision of Title I of the federal Clean Air Act, and
- (3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph.

[OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

- (1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
- (2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
- (3) For all emissions units not subject to an opacity limit promulgated under 40 CFR Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
 - (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
 - (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
 - (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or

- (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.
- (4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]
- (5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
- (6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
- (7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR Part 82, Subpart A]

- (1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
- (2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
- (3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: 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. [40 CFR Part 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR Part 82, Subpart F]

- (1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
- (2) 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;
- (3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
- (4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
- (5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
- (6) 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.

SECTION XXI. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [OAC 252:100-43-6]



MAJOR NSR PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2019-0607-C (M-3) PSD

Public Service Company of Oklahoma

having complied with the requirements of the law, is hereby granted permission to construct within the boundaries of the Northeastern Power Station at Section 4, Township 22N, Range 15E, approximately one mile south of Oologah, Rogers County, Oklahoma, subject to Standard Conditions dated October 16, 2025, and Specific Conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

DRAFT

Kendal Stegmann
Division Director

Date Issued

Lee Denham
Public Service Company of Oklahoma
212 E Sixth St.
Tulsa, OK 74119

SUBJECT: Construction Permit No. **2019-0607-C (M-3) PSD**
Public Service Company of Oklahoma
Northeastern Power Station
Facility ID: 212
Section 4, Township 22N, Range 15E, Rogers County, Oklahoma

Dear Lee Denham:

Enclosed is the permit authorizing the construction of the facility referenced above. Please note that this permit is issued subject to standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed through DEQ's electronic reporting system by April 1st of every year. Any questions concerning the submittal process should be referred to the Emissions Inventory Staff at (405) 702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at Elijah.Ecklund@deq.ok.gov or by phone at (918) 293-1622.

Sincerely,

DRAFT

Lee Warden, P.E.
Chief Engineer
AIR QUALITY DIVISION

Enclosures: AQD Public Review Process
Sample Notice Form
AQD Acronym List

Lee Denham
Public Service Company of Oklahoma
212 E Sixth St.
Tulsa, OK 74119

SUBJECT: Construction Permit No. **2019-0607-C (M-3) PSD**
Public Service Company of Oklahoma
Northeastern Power Station
Facility ID: 212
Section 4, Township 22N, Range 15E, Rogers County, Oklahoma

Dear Lee Denham:

Air Quality has received the permit application for the reference facility and completed initial review. This application has been determined to be a Tier II application. In accordance with 27A O.S. 2-14-301 and 302 and OAC 252:4-7-13(c), the enclosed draft permit is now ready for public review. The requirements for public review of the draft permit include the following steps, which **you** must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located (Instructions enclosed);
2. Submit sample notice and provide date of publication to **AQD 5 days prior to notice publishing;**
3. Provide for public review, for a period of 30 days following the date of the newspaper announcement, a copy of the application and draft permit at a convenient location (preferentially at a public location) within the county of the facility;
4. Send AQD a signed affidavit of publication for the notice(s) from Item #1 above within 20 days of publication of the draft permit. Any additional comments or requested changes you have for the draft permit or the application should be submitted within 30 days of publication.

Thank you for your cooperation. If you have any questions, please refer to the authorization number above and contact the permit writer at Elijah.Ecklund@deq.ok.gov, or at (918) 293-1622.

Sincerely,



Lee Warden, P.E.
Chief Engineer
AIR QUALITY DIVISION

NOTICE OF DRAFT PERMIT TIER II or TIER III AIR QUALITY PERMIT APPLICATION

APPLICANT RESPONSIBILITIES

Permit applicants are required to give public notice that a Tier II or Tier III draft permit has been prepared by DEQ. The notice must be published in one newspaper local to the site or facility. Note that if either the applicant or the public requests a public meeting, this must be arranged by the DEQ.

1. Complete the public notice using the samples provided by AQD below. Please use the version applicable to the requested permit action;
Version 1 – Traditional NSR process for a construction permit
Version 2 – Enhanced NSR process for a construction permit
Version 3 – initial Title V (Part 70 Source) operating permit, Title V operating permit renewal, Significant Modification to a Title V operating permit, and any Title V operating permit modification incorporating a construction permit that followed Traditional NSR process
2. Determine appropriate newspaper local to facility for publishing;
3. Submit sample notice and provide date of publication to AQD 5 days prior to notice publishing;
4. Upon publication, a signed affidavit of publication must be obtained from the newspaper and sent to AQD.

REQUIRED CONTENT (27A O.S. § 2-14-302 and OAC 252:4-7-13(c))

1. A statement that a Tier II or Tier III draft permit has been prepared by DEQ;
2. Name and address of the applicant;
3. Name, address, driving directions, legal description and county of the site or facility;
4. The type of permit or permit action being sought;
5. A description of activities to be regulated, including an estimate of emissions from the facility;
6. Location(s) where the application and draft permit may be reviewed (a location in the county where the site/facility is located must be included);
7. Name, address, and telephone number of the applicant and DEQ contacts;
8. Any additional information required by DEQ rules or deemed relevant by applicant;
9. A 30-day opportunity to request a formal public meeting on the draft permit.

SAMPLE NOTICES:

SAMPLE NOTICE (*Italicized print is to be filled in by the applicant.*):

DEQ NOTICE OF TIER ...II or III... DRAFT PERMIT

A Tier ...II or III... application for an air quality ...type of permit or permit action being sought (e.g., construction permit for a new major facility or construction permit for a modification at an existing major facility)... has been filed with the Oklahoma Department of Environmental Quality (DEQ) by applicant, ...name and address.

The applicant requests approval to ...brief description of purpose of application... at the ...site/facility name ... [proposed to be] located at ...physical address (if any), driving directions, and legal description including county....

In response to the application, DEQ has prepared a draft construction permit [modification] (Permit Number: ...xxxx-xxxx-x...), which may be reviewed at ...locations (one must be in the county where the site/facility is located)... or at the Air Quality Division's main office (see address below). The draft permit is also available for review under Permits for Public Review on the DEQ Web Page: <https://oklahoma.gov/deq.html>.

This draft permit would authorize the facility to emit the following regulated pollutants: (list each pollutant and amounts in tons per year (TPY)). [For facility modifications only, either add the phrase: , which represents (identify the emissions change involved in the modification)., or add the sentence: The modification will not result in a change in emissions.] [For PSD permits only, add: The project will consume the following increment levels: (list the amount of increment consumption for each pollutant in ug/m³).]

The public comment period ends 30 days after the date of publication of this notice. Any person may submit written comments concerning the draft permit to the Air Quality Division contact listed below or as directed through the corresponding online notice. [Modifications only, add: Only those issues relevant to the proposed modification(s) are open for comment.] A public meeting on the draft permit [modification] may also be requested in writing at the same address. Note that all public meetings are to be arranged and conducted by DEQ staff.

Information on all permit actions including draft permits, proposed permits, final issued permits and applicable review timelines are available in the Air Quality section of the DEQ Web page: <https://oklahoma.gov/deq.html>.

For additional information, contact ...names, addresses and telephone numbers of contact persons for the applicant, or contact DEQ at: Chief Engineer, Air Quality Division, 707 N. Robinson, Suite 4100, P.O. Box 1677, Oklahoma City, OK, 73101-1677. Phone No. (405) 702-4100.

Department of Environmental Quality (DEQ)
Air Quality Division (AQD)
Acronym List
9-8-2025

ACFM	Actual Cubic Feet per Minute	GACT	Generally Achievable Control Technology
AD	Applicability Determination	GAL	Gallon (gal)
AFRC	Air-to-Fuel Ratio Controller	GDF	Gasoline Dispensing Facility
API	American Petroleum Institute	GEP	Good Engineering Practice
ASTM	American Society for Testing and Materials	GHG	Greenhouse Gases
AVO	Audio, Visual, or Olfactory	GR	Grain(s) (gr)
BACT	Best Available Control Technology	H₂CO	Formaldehyde
BAE	Baseline Actual Emissions	H₂S	Hydrogen Sulfide
BBL	Barrel(s)	HAP	Hazardous Air Pollutants
BHP	Brake Horsepower (bhp)	HC	Hydrocarbon
BTEX	Benzene, Toluene, Ethylbenzene, Xylene	HCFC	Hydrochlorofluorocarbon
BTU	British thermal unit (Btu)	HFR	Horizontal Fixed Roof
C&E	Compliance and Enforcement	HON	Hazardous Organic NESHAP
CAA	Clean Air Act	HP	Horsepower (hp)
CAM	Compliance Assurance Monitoring	HR	Hour (hr)
CAS	Chemical Abstract Service	I&M	Inspection and Maintenance
CAAA	Clean Air Act Amendments	IBR	Incorporation by Reference
CC	Catalytic Converter	ICE	Internal Combustion Engine
CCR	Continuous Catalyst Regeneration	LAER	Lowest Achievable Emission Rate
CD	Consent Decree	LB	Pound(s) [Mass] (lb, lbs, lbm)
CEM	Continuous Emission Monitor	LB/HR	Pound(s) per Hour (lb/hr)
CFC	Chlorofluorocarbon	LDAR	Leak Detection and Repair
CFR	Code of Federal Regulations	LNG	Liquefied Natural Gas
CI	Compression Ignition	LT	Long Ton(s) (metric)
CNG	Compressed Natural Gas	LTPD	Long Tons per Day
CO	Carbon Monoxide or Consent Order	LPE	Legally and Practicably Enforceable
COA	Capable of Accommodating	M	Thousand (Roman Numeral)
COM	Continuous Opacity Monitor	MAAC	Maximum Acceptable Ambient Concentration
D	Day	MACT	Maximum Achievable Control Technology
DEF	Diesel Exhaust Fluid	MM	Prefix used for Million (Thousand-Thousand)
DG	Demand Growth	MMBTU	Million British Thermal Units (MMBtu)
DSCF	Dry Standard (At Standard Conditions) Cubic Foot (Feet)	MMBTUH	Million British Thermal Units per Hour (MMBtu/hr)
EGU	Electric Generating Unit	MMSCF	Million Standard Cubic Feet (MMscf)
EI	Emissions Inventory	MMSCFD	Million Standard Cubic Feet per Day
EPA	Environmental Protection Agency	MSDS	Material Safety Data Sheet
ESP	Electrostatic Precipitator	MWC	Municipal Waste Combustor
EUG	Emissions Unit Group	MWe	Megawatt Electrical
EUSGU	Electric Utility Steam Generating Unit	NA	Nonattainment
FCE	Full Compliance Evaluation	NAAQS	National Ambient Air Quality Standards
FCCU	Fluid Catalytic Cracking Unit	NAICS	North American Industry Classification System
FEL	Federally Enforceable Limit(s)	NESHAP	National Emission Standards for Hazardous Air Pollutants
FESOP	Federally Enforceable State Operating Permit	NH₃	Ammonia
FIP	Federal Implementation Plan	NMHC	Non-methane Hydrocarbon
FR	Federal Register	NGL	Natural Gas Liquids

NO₂	Nitrogen Dioxide	SCR	Selective Catalytic Reduction
NO_x	Nitrogen Oxides	SEP	Supplemental Environmental Project
NOI	Notice of Intent	SER	Significant Emission Rate
NSCR	Non-Selective Catalytic Reduction	SI	Spark Ignition
NSPS	New Source Performance Standards	SIC	Standard Industrial Classification
NSR	New Source Review	SIP	State Implementation Plan
		SNCR	Selective Non-Catalytic Reduction
O₃	Ozone	SO₂	Sulfur Dioxide
O&G	Oil and Gas	SO_x	Sulfur Oxides
O&M	Operation and Maintenance	SOP	Standard Operating Procedure
O&NG	Oil and Natural Gas	SRU	Sulfur Recovery Unit
OAC	Oklahoma Administrative Code		
OC	Oxidation Catalyst	T	Tons
OGI	Optical Gas Imaging	TAC	Toxic Air Contaminant
		TEG	Triethylene Glycol
PAH	Polycyclic Aromatic Hydrocarbons	THC	Total Hydrocarbons
PAE	Projected Actual Emissions	TPY	Tons per Year
PAL	Plant-wide Applicability Limit	TRS	Total Reduced Sulfur
Pb	Lead	TSP	Total Suspended Particulates
PBR	Permit by Rule	TV	Title V of the Federal Clean Air Act
PCB	Polychlorinated Biphenyls		
PCE	Partial Compliance Evaluation	µg/m³	Micrograms per Cubic Meter
PEA	Portable Emissions Analyzer	US EPA	U. S. Environmental Protection Agency
PFAS	Per- and Polyfluoroalkyl Substance		
PM	Particulate Matter	VFR	Vertical Fixed Roof
PM_{2.5}	Particulate Matter with an Aerodynamic Diameter <= 2.5 Micrometers	VMT	Vehicle Miles Traveled
PM₁₀	Particulate Matter with an Aerodynamic Diameter <= 10 Micrometers	VOC	Volatile Organic Compound
POM	Particulate Organic Matter or Polycyclic Organic Matter	VOL	Volatile Organic Liquid
ppb	Parts per Billion	VRT	Vapor Recovery Tower
ppm	Parts per Million	VRU	Vapor Recovery Unit
ppmv	Parts per Million Volume		
ppmvd	Parts per Million Dry Volume	YR	Year
PSD	Prevention of Significant Deterioration	2SLB	2-Stroke Lean Burn
psi	Pounds per Square Inch	4SLB	4-Stroke Lean Burn
psia	Pounds per Square Inch Absolute	4SRB	4-Stroke Rich Burn
psig	Pounds per Square Inch Gage		
RACT	Reasonably Available Control Technology		
RATA	Relative Accuracy Test Audit		
RAP	Regulated Air Pollutant or Reclaimed Asphalt Pavement		
RFG	Refinery Fuel Gas		
RICE	Reciprocating Internal Combustion Engine		
RO	Responsible Official		
ROAT	Regional Office at Tulsa		
RVP	Reid Vapor Pressure		
SCC	Source Classification Code		
SCF	Standard Cubic Foot		
SCFD	Standard Cubic Feet per Day		
SCFM	Standard Cubic Feet per Minute		

Date: September 24, 2026

Cherokee Nation
Attn: Chuck Hoskin, Jr., Principal Chief
P.O. Box 948
Tahlequah, OK 74465

Re: Permit Application No. 2019-0607-C (M-3) PSD
Public Service Company of Oklahoma, Northeastern Power Station (FAC ID 212)
Section 4, Township 22N, Range 15E, (36.43786, -95.70537)
Rogers County
Date Received: October 30, 2025

Dear Principal Chief Hoskin:

Pursuant to our Enhanced Tribal Engagement Policy, please accept this notification that the Oklahoma Department of Environmental Quality (DEQ), Air Quality Division (AQD), has received the above-referenced Tier II permit application and developed a draft permit. The public participation process requires the facility to notify the public by newspaper notice in a newspaper in the county of the proposed project of a 30-day public comment period on the draft permit. Since the proposed project falls within the Cherokee Nation's reservation boundaries, DEQ is providing this direct notice to the Cherokee Nation. This letter notification is in addition to the public newspaper notice required by the Uniform Environmental Permitting Act.

DEQ recognizes that the Cherokee Nation has important interests that could potentially be affected by the above-referenced project and welcomes the Cherokee Nation's engagement and input during the permit review process. DEQ's website provides information on the review process and access to the draft permit, filed application, and related documents: <https://applications.deq.ok.gov/PermitsPublicReview/>

If your staff would like additional information or would like to schedule an in-person meeting or conference call with DEQ to discuss the draft permit, please feel free to have them contact our Chief Engineer by email at lee.warden@deq.ok.gov, or by mail at:

Department of Environmental Quality, Air Quality Division
Attn: Lee Warden, Chief Engineer
P.O. Box 1677
Oklahoma City, OK, 73101-1677

If your staff has any questions, please have them reach out to Lee Warden at (405) 702-4237.

Sincerely,

Kendal Stegmann
Division Director
AIR QUALITY DIVISION

KDHE, BAR
Forbes Field, Building 283
Topeka, KS 66620

SUBJECT: Permit Number: **2019-0607-C (M-3) PSD**
Facility: Public Service Company of Oklahoma, Northeastern Power Station
Latitude: 36.43783°N; Longitude: 95.70537°W
Location: Section 4, Township 22N, Range 15E, Rogers County, Oklahoma
Permit Writer: Elijah Ecklund

Dear Sir / Madame:

The subject facility has requested a modification to an NSR construction permit for a Part 70 source. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - **Kansas** border, a copy of the draft permit will be provided to you upon request. The draft permit is also available for review on the Air Quality section of the DEQ web page at <https://oklahoma.gov/deq.html>.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at (918) 293-1622.

Sincerely,



Lee Warden, P.E.
Chief Engineer
AIR QUALITY DIVISION