

DRAFT/PROPOSED

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION

MEMORANDUM

May 25, 2022

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: Richard Groshong, Sr. Env. Programs Manager, Compliance & Enforcement

THROUGH: Phil Martin, P.E., Manager, Existing Source Permits Section

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

FROM: Iftekhar Hossain, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2019-0607-TVR3**
American Electric Power (AEP)
Public Service Company of Oklahoma (PSO)
Northeastern Power Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Direction: From US 169 and OK 88 approx. one mile south of Oologah, east
on OK 88 roughly 200 yards to driveway at 36.43783° N, 95.70537° W.

SECTION I. INTRODUCTION

American Electric Power (AEP) Public Service Company of Oklahoma (PSO) has submitted a Part 70 permit renewal application for their Northeastern Power Station (Northeastern). The facility is an electric utility plant (SIC 4911/NAICS 221112) and is located in an attainment area. The facility is currently operating under Part 70 operating permit No. 2012-918-TVR2 (M-2) issued on August 10, 2017. The facility is a major source for Prevention of Significant Deterioration (PSD) and a minor source of Hazardous Air Pollutants (HAPs).

No physical or operational changes have been made to the facility since the issuance of last permit [No. 2012-918-TVR2 (M-2)]. No changes to existing permit terms have been requested in this permit application, except the ‘administrative permit amendments (see SECTION III).’

The facility is an existing Prevention of Significant Deterioration (PSD) major source. The request for a Part 70 Operating permit renewal requires that this permit undergo **Tier II** application processing. Public review of the application and draft permit are required. A 45-day EPA review is also required.

Since the facility emits more than 100 TPY of a regulated pollutant, it is subject to Title V permitting requirements. Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) as outlined in Section III.

SECTION II. FACILITY 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. The 2003-410-C (M-6) PSD modification authorized installation of low-NO_x burners and overfire air (LNB/OFA) on Unit 2.

The boiler providing steam for Unit 3 is primarily coal-fired, with natural gas, and co-firing of coal and natural gas as secondary fuels. 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 coal-fired Unit 3 in advance of EPA’s Regional Haze requirements, under operating permit modification 2003-410-TRV (M-3), issued March 8, 2012. This was a major modification, and applicant had refined the system by “Refined Tuning” under the C (M-6) PSD permit, and performance testing has verified compliance with the NO_x and CO emission limits.

The pollution control project covered by application TVR (M-5) added 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 the TVR (M-5) permit – 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), and another originally serving Unit 3 and 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.

This permit includes fly ash handling equipment owned and operated by the ash management contractor, thus avoiding a separate Title V permit for that company. Fly ash generated by coal combustion at Northeastern Unit 3 was originally captured by an electrostatic precipitator (ESP) and initially stored in a fly ash silo. There have been two options for removal of the fly ash from the silo, although a third option due to the TVR (M-5) project will be discussed later in this Memorandum. Either option may be required to handle 100% of the fly ash captured by the ESP, depending on the marketability of the fly ash for sale.

The first option is to unload the fly ash into trucks via chutes at the bottom of the silo for transport and sale off-site. The trucks, having a capacity of approximately 25 tons, are fully enclosed and equipped with “portholes” on top for receiving the fly ash. After loading, the trucks move to an

adjacent wash station where they are manually washed, and then travel approximately one mile over a paved road to exit the plant site.

The second option utilizes a pneumatic trailer for permanent disposal as ash rock. Fly ash is loaded into modified on-site pneumatic tanker trailers using the same chutes as used in option one. The hatches are closed after loading and the truck drives to the landfill area. A water truck moistens the area where the ash is to be deposited. The truck slows to 2 or 3 miles per hour upon arrival at the site and the pneumatic valves are opened, allowing the fly ash to drop from the bottom of the trailer, which has full skirting mounted to contain the fly ash. Deposition occurs for 30 seconds, with no additional air input. A water truck follows immediately behind this deposition, providing additional moisture for the fly ash, both to control dust and also to solidify the ash-water mixture. This mixture is then rolled, spread, and compacted by a motor grader or other heavy equipment. A water truck follows the grader, watering the area for the next load or for further dust control, as necessary. The weight of the haul truck, water truck, and grader, combined with the number of trips made over the area, further compact the material. The compacted material continues to be watered occasionally to maintain dust control and assist in curing. Eventually, the mixture will cure into "ash rock." Ash rock may remain in the landfill indefinitely, or may be recovered at some future date for other uses.

The third option is for the recovered fly ash rock to be loaded into open 15-ton capacity trucks using a front end loader, covered, and then transported one mile over an unpaved road to the truck wash station. After the truck is manually washed, it travels one mile over a paved road to exit the plant site.

The TVR (M-5) project involved the addition of an activated carbon injection (ACI) system to control mercury within the flue gas of Unit #3, and the addition of a dry sorbent injection (DSI) system to control both acid gases and SO₂. Both systems were added downstream of the electrostatic precipitator (ESP) for Unit #3. Finally, a fabric filter baghouse (FF) was added downstream of the ACI and DSI systems, to capture particulate emissions from the treated flue gas stream. Powdered activated carbon (PAC) is delivered by differential pressure from trucks to a storage silo. Next, PAC flows to weigh bins, then via pneumatic injection ports into the Unit 3 ductwork, upstream of the fabric filter. The ACI injection rate is expected to be a nominal 250 lb/hr, but depends on system variables. The DSI system specifies the use of sodium bicarbonate (SBC), which is delivered by differential pressure from trucks or rail cars to two storage silos. SBC is then screw fed to air classifier mills that process and pneumatically feed the SBC to injection ports in Unit 3 ductwork upstream of the fabric filter. The SBC injection rate is expected to be a nominal 5,250 lb/hr., dependent upon system variables. Material captured from the fabric filter is referred to as byproduct, and is sent pneumatically to a byproduct storage silo. Byproduct can be mixed with flyash and water in a pug mill to reduce dust emissions when loaded onto trucks for hauling to the landfill or it may be mechanically mixed with flyash directly on the landfill. Dry byproduct may also be loaded to the truck by a sealed system that sends displaced air into the silo, or the byproduct silo can be bypassed using vacuum totes loaded directly from the ACI/DSI/FF baghouse hoppers. Each of the four silos has a bin vent filter on top, as do the classifier mills. The filters are for product recovery, and only secondarily providing emission control. Fugitive emissions are created by the trucking involved.

Bottom ash is wet-sluiced to the removal area of the Bottom Ash Pond (BAP) during unit operations. The bottom ash is routinely reclaimed, loaded into trucks and transported to the landfill for storage, or used for beneficial reuse.

The use of natural gas as ignition fuel has trivial effects on emissions of SO₂ as compared with the effects due to coal. The proposed use of petroleum coke (pet coke) is treated in several parts of this permit. Unit 3 has always had the ability to burn pet coke as an alternate fuel for coal and it has not been proscribed. It should be assumed as being represented by coal in the following tables. Auxboiler 3 operates under a 10% annual capacity factor. As indicated, Unit 3 is primarily coal-fired, with natural gas, and co-firing of coal and natural gas as secondary fuels. The flexibility of using those secondary fuels is implied. The duration of actual fuel hours of operation in calendar year 2018 follows.

Unit 1A		Unit 1B		Unit 2		Unit 3	
Fuel	Hours	Fuel	Hours	Fuel	Hours	Fuel	Hours
NG	5,413 (100%)	NG	5,721 (100%)	NG	2,133 (100%)	Coal	7,136 (99.6%)
						NG	26 (0.4%)

Natural gas firing is the mode chosen for start-up and flame stabilization for coal-firing at Unit 3, and does not generally represent long-term natural gas use. Although Unit 3 has the capability to be co-fired on coal and gas, no co-firing for commercial generation occurred during 2018.

Incorporation of EPA Approved and Promulgated Revised BART (dated March 7, 2014)

Background:

EPA published in the Federal Register (FR) document (79 FR 12944, Mar 7, 2014) which states the final US EPA requirements for Regional Haze and Best Available Retrofit Technology (BART) compliance activities for PSO Northeastern, as of March 7, 2014. The requirements that the applicant suggested to be included in the Northeastern TVR3 permit are items (5) and (6) of the said FR which pertain to a SO₂ emissions limit and capacity utilization decreases, respectively, for Northeastern Unit 3.

The FR also references to the possibility of lowering the Northeastern Unit 3 SO₂ emissions below 0.4 lb/MMBTU. Those discussions between DEQ and AEP have not been completed yet. The requirements will be included in this permit and will become effective after the resolution becomes available.

Earlier documents which were developed prior to the FR document, are referenced within this FR document. Those requirements which were still valid as of March 7, 2014, are included within the FR document.

From the Revised Regional Haze SIP in the referenced Federal Register, Item (6) refers to what was originally proposed as the Annual Capacity Factor restrictions for Northeastern’s coal-fired Unit 3. Those restrictions were listed in the “Term Sheet” document, as Item 1.(g) on page 2 of 7, copied here:

1.(g) The RHA will require that beginning in calendar year 2021, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW times 8,760 hours) for the operating coal-fired generating unit at Northeastern Station will be reduced as follows:

- (i). to no more than 70 percent in calendar years 2021 and 2022;
- (ii). to no more than 60 percent in calendar years 2023 and 2024; and
- (iii). to no more than 50 percent in calendar years 2025 and 2026.

SECTION III REQUESTED CHANGES

The facility requested the following changes to the permit by ‘administrative permit amendments.

Comments #1:

Specific Condition 1.C. EUG 7 and EUG 8: Current Part 70 operating permit (No. 2012-918- TVR2 (M-2)) presented the EUG tables 7 and 8 as follows:

EUG 7 Emergency Reclaim Water Curtain (Make: “Engart”, July 2009)

EU	Point	Make/Model	Const Date
7	7	Peabody #S1-5	Apr, 1974

EUG 8 Crusher House Water Curtain (Make: “Engart”, July 2009)

EU	Point	Make/Model	Const Date
8	8	Peabody #S2-9	Apr, 1974

AEP Justification:

The text of the tables was simplified. This is an administrative amendment.

DEQ Determination:

DEQ concurs with AEP’s justification. The tables of Specific Condition 1.C. EUG 7 and EUG 8 have therefore been revised as follows:

EUG 7 Emergency Reclaim Water Curtain

EU	Point	Make/Model	Const Date
7	7	Engart	July 2009

EUG 8 Crusher House Water Curtain

EU	Point	Make/Model	Const Date
8	8	Engart	July 2009

Comments #2:

Specific Condition 1.E. EUG 16: The current permit states that:

The engine shall be operated as follows.

- a. The owner/operator shall comply with this NESHAP Subpart ZZZZ (40 CFR §63.6640(f)).
- b. The engine shall be fueled with diesel with a maximum sulfur content of 0.0015% by weight.
- c. The operating hours for each emergency engine shall be limited to 100 hours/year.

AEP Justification:

AEP clarified item c above and added item d to improve clarity and accuracy.

DEQ Determination:

DEQ concurs with AEP's justification. Item c is revised and item d is added as shown below:

- a. The owner/operator shall comply with this NESHAP Subpart ZZZZ (40 CFR §63.6640(f)).
- b. The engine shall be fueled with diesel with a maximum sulfur content of 0.0015% by weight.
- c. The operating hours for each emergency engine shall be limited to 100 hours/year for maintenance, testing, emergency demand response, and deviation of voltage or frequency of 5% or greater from standard voltage or frequency.
- d. There is no time limit on the use of emergency stationary RICE in emergency situations.

Comments #3:

Specific Condition 1.F. EUG Chemstore:

EUG ChemStore Stored Chemicals: The current permit states that, "This EUG covers various stored chemicals, including hydrogen, ammonia, and hydrazine."

AEP Justification:

AEP does not store hydrazine; therefore, has requested to remove it.

DEQ Determination:

DEQ concurs with AEP's justification. Hydrazine has been removed from the sentence in both the Memorandum and Specific Conditions.

Comments #4:

Specific Condition 4a. The current permit states that:

The facility is subject to the Acid Rain Program and shall comply with all applicable requirements as listed in renewal Permit No. 2014-1749-ARR3, including the following. [40 CFR Part 75]

- a. Compliance with NO_x emission limit for coal units, as described in the Phase II NO_x Averaging Plan, dated December 16, 2011, and SO₂ allowances.

AEP Justification:

The “Phase II NO_x Averaging Plan” is no longer in effect. Now, every AEP coal-fired EGU meets its NO_x limit, so that Plan is no longer necessary.

DEQ Determination:

DEQ concurs with AEP’s justification. Now SC #4a reads as:

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 SO₂ allowances.

Comments #5:

Keep only first sentence of the SC and remove rest of it. In the current permit, it reads as:

7. The permittee shall not replace the modified burners on Unit 2, or the low-NO_x concentric firing systems of Unit 3, or the electrostatic precipitators on Unit 3 except by devices of equal or greater control efficiency. NO_x control efficiency of the modified burners is estimated to be 40%, and Unit 3 NO_x emissions are anticipated to be well below the acid rain requirements considering after installation of the low-NO_x concentric firing systems. The PM control efficiency of the ESPs is estimated to be 99.6%. By the extension date of April 16, 2016, the Unit 3 ESP started utilizing as a product recovery device only, not as a control device. The fabric filter has become the control device for Unit 3.
[OAC 252:100-43]

AEP Justification:

NO_x control efficiency is not measured, and is not relevant to this requirement.

DEQ Determination:

DEQ concurs with AEP’s justification. Now SC #7 reads as:

7. The permittee shall not replace the modified burners on Unit 2, or the low-NO_x concentric firing systems of Unit 3.

Comments #6:

Specific Condition 14. The current permit states that:

14. The following records shall be maintained on-site. All such records shall be made available to regulatory personnel upon request. These records shall be maintained for a period of at least five years after the time they are made.
[OAC 252:100-43]

- b. Sulfur content of fuel oil (on an as-burned basis and each new delivery).
 - i. Data demonstrating compliance with NSPS Subpart GG, as required by Specific Condition #11.

AEP Justification:

14 b. Fuel oil is no longer delivered to, and used at, this facility

14 i. Correction to typographical error of the SC reference.

DEQ Determination:

DEQ concurs with AEP's justification. Corrections to the permit are done as follows:

14 b. Deleted. The rest of the SC #14 has been renumbered.

14 h. Data demonstrating compliance with NSPS Subpart GG, as required by Specific Condition #10.

Comments #7:

Specific Condition 15 c. The current permit states that:

The following records shall be maintained on-site to verify insignificant activities.

[OAC 252:100-43]

- c. Operation of each stationary reciprocating engine burning natural gas, gasoline, aircraft fuels, or oil, used for emergency power generation less than 500 hours per year (annual total hours).

AEP Justification:

There are two emergency generators at the facility. However, emergency generators are no longer "insignificant activities", because they are now subject to NESHAP Subpart ZZZZ. Records required to keep as per 40 CFR §63.6640(f).

DEQ Determination:

DEQ concurs with AEP's justification. Item #15c is deleted and #15 renumbered. Another recordkeeping item is added to the SC #14 (p). The condition will read as:

- (n) Records required under 40 CFR §63.6640(f), per SC #1.E EUG 16.

Comments #8:

Specific Condition 15 f of current permit. The current permit states that:

- (f) Records for any other activity, demonstrating that emissions are less than 5 TPY.

AEP Justification:

There are certain PSO Northeastern NES activities such as welding, torch cutting, & soldering are **Trivial** due to maintenance purposes only. AEP recommends to revise the condition for clarity.

DEQ Determination:

DEQ concurs with AEP's justification. Item #15f (now, 15e) is revised and is read as:

- 15 e. records for any other activity, demonstrating that emissions are less than 5TPY unless defined as Trivial as listed in OAC 252:100 (Appendix J)

Comments #9:

Specific Condition 16 c and 16 e. The current permit reads as:

16. The boilers in EUG 2 and 3 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including, but not limited to, the following. [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

- c. Within 60 days of achieving maximum power output from each affected facility after modification or installation of BART, but not to exceed 180 days from initial start-up of the affected facility, the permittee shall be in compliance with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer’s data and an agreed-upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits.

EU ID#	Point ID#	NO _x	Averaging Period
2	2	0.28 lb/MMBTU	30-day rolling

EU ID#	Point ID#	NO _x ¹ Emission Limit	Averaging Period
3	3	0.15 lb/MMBTU	30-day rolling

¹Limits apply only when units are firing 100% on coal.

EU ID#	Point ID#	PM ₁₀ ¹ Emission Limit	Averaging Period	Combined Annual Emission Rate
3	3	0.10 lb/MMBTU	3-hour	2,092 TPY 12-month rolling

¹Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch. As part of the permitting process, PSO will be required to propose emission limits for front and back half reflective of the control technology and consistent with performance test results.

EU ID#	Point ID#	SO ₂ Emission Limit	Averaging Period	Annual Emission Rate
3	3	0.40 lb/MMBTU	30-day rolling	8,366 TPY 12-month rolling
		1,910 lb/hr		

- d. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.
- e. Within 60 days of achieving maximum power output from each boiler, after modification of the boilers, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities.

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

AEP Justification:

SC 16 c. The deadline has elapsed, the construction permit has been superseded by operating permits and the proposed emission limits for front and back half have been addressed. Therefore, those statements can be modified as provided below in SC 16 c.

SC 16 e. The deadline has elapsed. Therefore, SC 16 e can be deleted.

DEQ Determination:

DEQ concurs with AEP’s justification. The revised SC 16 c will now read as follows. SC 16 e will be deleted.

16 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.

EU ID#	Point ID#	NO _x	Averaging Period
2	2	0.28 lb/MMBTU	30-day rolling

EU ID#	Point ID#	NO _x ¹ Emission Limit	Averaging Period
3	3	0.15 lb/MMBTU	30-day rolling

¹Limits apply only when units are firing 100% on coal.

EU ID#	Point ID#	PM ₁₀ ¹ Emission Limit	Averaging Period	Combined Annual Emission Rate
3	3	0.10 lb/MMBTU	3-hour	2,092 TPY 12-month rolling

EU ID#	Point ID#	SO ₂ Emission Limit	Averaging Period	Annual Emission Rate
3	3	0.40 lb/MMBTU	30-day rolling	8,366 TPY 12-month rolling
		1,910 lb/hr		

- d. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da. [OAC 252:100-8-6(a)]

Comments #10:

Due to the FR document ((79 FR 12944, Mar 7, 2014) which includes the requirements of revised regional haze SIP, the following schedule should be included into the PSO Title V permit.

1.(g) The RHA will require that beginning in calendar year 2021, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW times 8,760 hours) for the operating coal-fired generating unit at Northeastern Station will be reduced as follows:

- (i). to no more than 70 percent in calendar years 2021 and 2022;

- (ii). to no more than 60 percent in calendar years 2023 and 2024; and
- (iii). to no more than 50 percent in calendar years 2025 and 2026.

AEP Justification

AEP recommends that an additional specific condition be added to reflect the Annual Capacity Factor (ACF) reductions listed in the Regional Haze Agreement (RHA) that is laid out in Section II (Facility Description).

DEQ Determination:

DEQ added a permit condition (#17) to reflect ACF reduction schedule.

SECTION IV. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs).

EUG 1 Gas Turbines and Heat Recovery Steam Generators (HRSG) *

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
1	1A	GE MS7001FA S/N 297510	160	1,684**	Jan. 2000
1	1B	GE MS7001FA S/N 297511	160	1,684**	Jan. 2000

* 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.

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

EUG 2 Grandfathered Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
2	2	Babcock and Wilcox UP-60	495	4,754	Mar, 1970

EUG 3 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
3	3	Combustion Engineering #4974 SCRR	490	4,775	Apr, 1974

EUG Aux 1/2 Steam Generator

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 1/2	Aux 1/2	Babcock and Wilcox FM 117-97	N/A	220	Mar, 1997

EUG Aux 3 Steam Generator

EU	Point	Make/Model	MW	MMBUTH	Const Date
Aux 3	Aux 3	Combustion Engineering #3M1004	N/A	239	Apr 1974

EUG 6A & 6B Rotary Car Dumper Baghouses (East and West)

EU	Point	Make/Model	Const Date
6	6	Peabody #03-21	Apr, 1974

EUG 7 Emergency Reclaim Water Curtain

EU	Point	Make/Model	Const Date
7	7	Engart	July 2009

EUG 8 Crusher House Water Curtain

EU	Point	Make/Model	Const Date
8	8	Engart	July 2009

EUG 9 Unit 3 Coal Silo (Cascade) Dust Collector

EU	Point	Make/Model	Const Date
9	9	Peabody #D2-10	Apr, 1974

The next five EUGs are established only for identification of the origin of various fugitive emissions. EU ID# and Point # are identical with the EUG#.

EUG 11 Coal Handling Fugitives

EUG 12 Fly Ash Handling Fugitives

EUG 13 Bottom Ash Handling Fugitives

EUG 14 Byproduct Handling Fugitives

EUG 15 Bin Vent Filters

EU	Point	Source	Const Date
15	1	Sorbent silo 1	2/2016
15	2	Sorbent silo 2	2/2016
15	3	Activated carbon silo	2/2016
15	4	Byproduct silo	2/2016
15	5	Classifier mill 1	2/2016
15	6	Classifier mill 2	2/2016

EUG 16 Emergency Engines (for Generators)

EU	HP	Description	Fuel Type	Function	Mfg. Date
GEN 1/2	3,600	General Motors, Model MP45A (Electro-Motive Division MU-Type Power Plant)	Diesel-fired	for service at Units 1 & 2	05/1968
GEN 3	1,476	Detroit Diesel Allison, Model 16V-149T (Supplied by United Engines, Inc., descriptor B/M 6571/6572 M-22C)	Diesel-fired	for service at Unit 3	02/1979

EUG ChemStore Stored Chemicals

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

EUG Coal Pile

This covers fugitive emissions from wind erosion of the coal pile.

EUG Plantwide Entire Facility

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

EUG Insignificant Sources

Northeastern Station identifies various pieces of equipment as fitting the insignificant definition. These include ten hydrocarbon storage tanks, a gasoline pump and storage tank, and a fly ash landfill.

STACK PARAMETERS

EUG	Point	Height (Ft)	Dimensions	Flow (ACFM)	Temperature (°F)
1	1A	150	18.83' diameter	1,080,000	200
1	1B	150	18.83' diameter	1,080,000	200
2	2	183	18.0' diameter	815,626	249
3	3	600	27.0' diameter	1,556,205	250
Aux 1/2	Aux 1/2	168.5	4.5' diameter	54,287	555
Aux 3	Aux 3	40	8' diameter	88,500	669
6	6A, 6B	N/A	76" × 48" (each)	153,680 (each)	Ambient
7	7	N/A	15.5" × 14"	4,500	Ambient
8	8	N/A	32" × 29"	20,600	Ambient
9	9	N/A	42" × 47"	47,950	Ambient

SECTION V. EMISSIONS

Emission factors for EUG 2 through EUG 6 in the memorandum for 2003-410-TVR (M-5) were 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, and coal handling TSP and PM₁₀ factors are found in Section 13.2. NO_x and SO₂ emissions are based on CEMS data of units 1A, 1B, 2, and 3. The TSP factor for Unit 3 was based on stack testing. As of April 16, 2016, the electrostatic precipitator (ESP) for Unit 3 has been used as a product recovery device, and the ESP reduces particulate matter (PM) from the exhaust. As of April 16, 2016, the Activated Carbon Injection (ACI), Dry Sorbent Injection (DSI), and Fabric Filter (FF) systems have been the primary air pollution control devices for mercury, SO₂, acid gases, and PM emissions. Details regarding the ACI, DSI, and FF systems are provided later in this section.

Emissions for point sources are established as follows. When a scenario calls for a mix of fuels, the more polluting fuel is taken for the hourly rate, with the annual emissions representing 4,380

hours of each fuel. Unit 2 has the capability of burning 4.63 MMCFH of gas (40,590 MMCFY). Unit 3 has the capability of burning 266 TPH of coal (2.33×10^6 TPY). Coal is assumed to have an average heating value of 16.4 MMBTU per ton, based on the data provided by coal supplier. Auxiliary boilers burn only natural gas.

The facility is also subject to Acid Rain Renewal Permit No. 2019-0782-ARR4. For US EPA Regional Haze compliance, Unit 2 has a NO_x limit of 0.28 lb/MMBTU, and Unit 3 has a NO_x limit of 0.15 lb/MMBTU, and each are rolling 30-calendar day averages.

Coal handling equipment is considered to operate continuously. Because of the difficulty involved in presenting the myriad emission factors within the emission table, the AP-42 factors used as default values when test data are not available are listed here. Note that AP-42 gas factors assume a heating value of 1,020 BTU/CF. The foregoing discussion of emission factors used in calculations for EUGs 2, 3, Aux 1/2, and Aux 3 is summarized in the following table. To recap the preceding discussion and as a precaution about the proper use of these factors, note the following. The 0.15 lb/MMBTU limit proposed for the C (M-6) PSD project is a 30-day rolling BART average. The construction permit for Unit 3 did not set limits for CO emissions, but the C (M-6) PSD project did. Coal is assumed to have a heating value of 16.4 MMBTU/Ton. Actual NO_x and SO₂ emissions were calculated by CEMS.

AP-42 Emissions Factors

Pollutant	Gas	Oil	Coal
	lbs/MMCF AP-42 (07/98)	lbs/10 ³ gallons AP-42 (05/10)	lbs/ton AP-42 (09/98)
TSP	7.6	2	10A** (filterable) 0.02 (condensable)***
PM ₁₀	7.6	2	2.3A** (filterable) 0.02 (condensable)***
PM _{2.5}	7.6	1.3	0.01A** (filterable) 0.02 (condensable)***
SO ₂	0.6	142S*	38S*
NO _x	140	10	7.2
CO	84	5	0.50
VOC	5.5	0.556	0.06

*S = sulfur content in percent; ** A = ash content; *** units are in lb/MMBTU

Emission factors for turbines 1A and 1B are based on manufacturer’s guarantees. To assure conservatively high results, pound per hour figures are taken at -8°F, while TPY data are taken at average ambient. Note that the NO_x and CO values for the turbines are based on ppmv dry at 15% O₂. 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. 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 content of 0.25 gr/100 dscf and an hourly high of 5 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 1 turbines and HRSGs are valid for all operating scenarios.

Pollutant	Emission Factor	Turbine (ea)		Factor lb/MMBTU	Duct burner (ea)		Totals	
		lbs/hr	TPY		lbs/hr	TPY	lbs/hr	TPY
NO _x	15 ppm	108	418	0.09	8.91	39.0	234	914
SO ₂	0.2 ppm	1.18	5.19	<0.001	1.41	0.31	5.18	11
PM ₁₀ = PM _{2.5}	0.011 lb/MMBTU	20.9	81.1	0.01	0.99	4.34	43.78	171
VOC	0.1 ppm	0.40	1.49	0.001	0.10	0.43	1.0	3.84
CO	12 ppm	51.7	198	0.09	8.91	39.0	121	474
H ₂ SO ₄	Per SO ₂	0.06	0.24	Per SO ₂	0.11	0.48	0.34	1.44

Pollutant	Units 1A & 1B		Unit 2		Unit 3	
	Lb/hr	TPY	Lb/hr	TPY	Lb/hr	TPY
TSP	43.8	171	35.4	155	64.9	284
PM ₁₀	43.8	171	35.4	155	64.9	284
SO ₂	1.26	11.0	2.80	12.3	1,910	8,366
NO _x	234	914	2,139	5,622	3,343	2,928
CO	121	474	352	1,541	N/A	6,797
VOC	1.00	3.84	25.6	112	17.7	77.5

Lbs/hr values for Auxboiler 3 are taken from Specific Condition No. 1 of the original Part 70 permit.

EMISSIONS FROM AUXILIARY BOILER 1/2 & 3

Pollutant	Emission factor*	213 MCFH Lb/hr	280 MMCFY TPY
TSP = PM ₁₀	7.6 lb/MMCF	1.62	1.06
SO ₂	0.6 lb/MMCF	0.13	0.08
NO _x	280 lb/MMCF	59.6	39.2
CO	84 lb/MMCF	17.9	11.8
VOC	5.5 lb/MMCF	1.17	0.77

*Based on a gas heating value of 1,032 BTU/CF.

PARTICULATE EMISSIONS FROM COAL HANDLING (EUGs 6-9)

Source	Pollutant	Emission factor, Lb/ton*	Coal handled		Emissions	
			TPH	TPY x 10 ³	Lb/hr	TPY
Car Dumper	TSP	6.551 x 10 ⁻⁶	2,835	4,621	1.86 x 10 ⁻²	1.51 x 10 ⁻²
	PM ₁₀	3.098 x 10 ⁻⁶	2,835	4,621	8.78 x 10 ⁻³	7.16 x 10 ⁻³
Emergency Reclaim	TSP	2.184 x 10 ⁻⁶	752	233	1.64 x 10 ⁻³	2.54 x 10 ⁻⁴
	PM ₁₀	1.033 x 10 ⁻⁶	752	233	7.77 x 10 ⁻⁴	1.20 x 10 ⁻⁴
Crusher	TSP	2.184 x 10 ⁻⁶	545	4,776	1.19 x 10 ⁻⁶	5.22 x 10 ⁻³
	PM ₁₀	1.033 x 10 ⁻⁶	545	4,776	5.63 x 10 ⁻⁴	2.47 x 10 ⁻³

Source	Pollutant	Emission factor, Lb/ton*	Coal handled		Emissions	
			TPH	TPY x 10 ³	Lb/hr	TPY
Car Dumper	TSP	6.551 x 10 ⁻⁶	2,835	4,621	1.86 x 10 ⁻²	1.51 x 10 ⁻²
	PM ₁₀	3.098 x 10 ⁻⁶	2,835	4,621	8.78 x 10 ⁻³	7.16 x 10 ⁻³
Unit 3 Silo	TSP	2.184 x 10 ⁻⁶	301	2,330	6.57 x 10 ⁻⁴	2.54 x 10 ⁻³
	PM ₁₀	1.033 x 10 ⁻⁶	301	2,330	3.11 x 10 ⁻⁴	1.20 x 10 ⁻³

*All emission factors are calculated utilizing Equation 1 from AP-42 (1/95) Section 13.2.4 using a conservatively high average wind speed value of 9 mph, and then applying the 99.9% efficiency of the baghouse filter. Although this equation may not be entirely appropriate for crusher emissions, it yields values within 8% of those suggested by the analysis in Section 11.19.2 of AP-42, an insignificant difference given the net emission level.

EUG 16 Emergency Engines (for Emergency Generators)

Engine Emission Factors, lb/hp-hr

Name/Model	NO _x	CO	SO _x	PM	VOC
3,600-hp General Motors, Model MP45A (GEN 1/2)	0.024	0.0055	0.0000121	0.0007	0.000642
1,476-HP Detroit Diesel Allison, Model 16V-149T (GEN 3)	0.024	0.0055	0.0000121	0.0007	0.000642

Emission Factors from US EPA AP-42 (10/96), Table 3.4-1. Sulfur content of diesel fuel: 0.0015%

Potential Hourly Emissions

Emergency Generator	Potential Hourly Emissions				
	NO _x (lb/hr)	CO (lb/hr)	SO _x (lb/hr)	PM (lb/hr)	VOC (lb/hr)
GEN 1/2	86.40	19.80	0.044	2.52	2.31
GEN 3	35.42	8.12	0.018	1.03	0.95

40 CFR Part 63 Subpart ZZZZ: Emergency Generator Emissions

Emergency Generator	Yearly Emissions (based on 100 hours of operation)				
	NO _x (TPY)	CO (TPY)	SO _x (TPY)	PM (TPY)	VOC (TPY)
GEN 1/2	4.32	0.99	0.002	0.13	0.12
GEN 3	1.77	0.41	0.001	0.05	0.05

PARTICULATE EMISSIONS FROM MATERIAL HANDLING (EUGs 11-15)

There are 30 acres of “inactive” coal pile and 10 acres of “active” coal pile, per the “frequency of disturbance” discussion in AP-42 (1/95) Section 13.2.5. Emissions from EUGs 11 and 12 were calculated using factors from AP-42 Section 11.19.2 (8/04). Since these fugitive emissions may be considered to be continuous, hourly figures are calculated by dividing annual estimates by 8,760 hours. All data are taken from the 1997 Turnaround Document.

EUG	Description	TSP		PM ₁₀	
		lb/hr	TPY	lb/hr	TPY
11	Coal stockpiles	2.60	11.4	1.25	5.46
12	Flyash handling/silo	1.88	8.22	0.95	4.17
13	Bottom ash handling	0.31	1.37	0.16	0.70

Fly ash collection and transportation from the ESPs is enclosed within the ash handling system until the material is loaded into trucks. The following calculations distinguish among the fly ash that is sold off-site, landfilled on-site, or landfilled initially and later sold off-site. No readily available emission factors are found for this loading, so it is treated like the drop operation described in Section 13.2.4 of AP-42 (11/06), using Equation 1 from the section. Thus,

$$E = \{k(0.0032)(U/5)^{1.3}\} \div \{(M/2)^{1.4}\}, \text{ where}$$

- K = 0.35 (dimensionless, for PM₁₀),
- U = 10 mph (wind velocity),
- M = 0.25% (moisture content), yielding
- E = emission factor (0.051 lbs/ton).

Note that despite the fact that the ash handling system moistens the material, moisture content is taken at the lowest value offered in the tables associated with the equation, maximizing the emission factor. Similarly, although the operation is protected from the wind, a relatively high wind speed is selected, also tending to maximize the emission factor. Using the emission factor generated by this equation with annual throughput of 207,995 tons yields emissions of 5.27 TPY.

For ash landfilled on-site, trucks are assumed to travel two miles for each 15-ton load of fly ash, and the road is assumed to be unpaved. Using equation 1a from Section 13.2.2.2 of AP-42 (11/06) to calculate fugitive emissions from unpaved roads yields

$$E = k(s/12)^a(W/3)^b, \text{ where}$$

- s = 6.4% (moisture content of road silt, chosen from Table 13.2.2-1),
- W = 15 tons per truck load,
- k = 1.5, a = 0.9, b = 0.45 (all dimensionless constants from Table 13.2.2-2 for PM₁₀), and
- E = 1.758 lbs/VMT (vehicle miles traveled).

Landfilling an annual total of 207,955 tons of fly ash requires 27,727 miles of travel, thus PM₁₀ emissions are 24.37 TPY.

For ash shipped off-site for sale, trucks are assumed to travel one mile for each 25-ton load of fly ash, and the road is assumed to be paved. Using Equation (1) from Section 13.2.1.3 of AP-42 (11/06) to calculate fugitive emissions from unpaved roads yields

$$E = k(sL/2)^{0.65}(W/3)^{1.5}-C, \text{ where}$$

k = 0.016 (dimensionless constant from Table 13.2.1-1 for PM10),
 sL = 7.4 g/m² (road surface silt loading, chosen from Table 13.2.2-4),
 W = 25 tons per truck load,
 C = 0.00047 lb/VMT (Emission factor from Table 13.2.1-2 for exhaust, brake wear, and tire wear for PM10)
 E = 0.896 lbs/VMT (vehicle miles traveled).

Off-site sales of an annual total of 207,955 tons of fly ash requires 8,318.2 miles of travel, thus PM₁₀ emissions are 3.73 TPY.

As an additional activity, fly ash that has been landfilled could later be sold off-site. In that case, trucks are assumed to travel one mile on an unpaved road, and one mile on a paved road. Using the aforementioned AP-42 equations, constants, and variables from Sections 13.2.1.3 and 13.2.2.2 to calculate the emission factors for 15-ton trucks, the PM₁₀ emission factors are 1.758 lbs/VMT for the unpaved road, and 0.414 lbs/BMT for the paved road. This activity at the facility occurs only infrequently.

There are PM emissions from handling various materials, including PAC, SBC, and byproduct, with respect to storage and transportation of these new operations. The fabric filter adds another layer of control to that provided by the ESP. Emission calculations for the new operations assume maximum throughput. For instance, each bin vent has a manufacturer’s guarantee of 0.01 grains per SCF. Given the annual flow associated with delivery of the particular product, an annual estimate of PM emissions may be made. Hourly usage of each material, the capacity of the haul trucks, and the roundtrip distance traveled, allow for vehicle miles traveled (VMT)) calculations for the SBC and PAC. A similar calculation, based on an estimated 165 tons per day of byproduct may be performed, noting that each trip is divided between 1,100 feet on paved roads and 11,600 feet on unpaved roads. In all cases, 94 days per year are assumed for measurable precipitation. All emissions calculations relating to travel use Equations 1, 2, and 3 from Section 13.2.2 of AP-42. A drop point calculation was made for the landfill, using numbers referenced above and methods shown in Section 13.2.4 of AP-42 (11/06). Details of the various constants, such as the k-factor, are available in the application, but the numbers generated are fairly small, so the following table recites the points involved and their contributions to the overall emissions.

Point ID	Process	Emissions (TPY)		
		PM	PM ₁₀	PM _{2.5}
<i>Reagent (SBC) handling and delivery</i>				
EUG-15, EU 1	Storage silo 1	0.200	0.168	0.044
EUG-15, EU 2	Storage silo 2	0.200	0.168	0.044
EUG-15, EU 5	Classifier mill separator 1	1.877	1.573	0.414
EUG-15, EU 6	Classifier mill separator 2	1.877	1.573	0.414
<i>PAC handling system</i>				
EUG-15, EU 3	PAC storage silo	0.24	0.20	0.05
<i>Ash/byproduct handling systems</i>				
EUG-14, TP-01	Truck loading	0.079	0.066	0.017
EUG-14, NP-01	SBC & PAC paved roads	0.51	0.10	0.03
EUG-14, NP-02	Byproduct paved roads	0.11	0.02	0.01

Point ID	Process	Emissions (TPY)		
		PM	PM ₁₀	PM _{2.5}
	Byproduct unpaved roads	5.48	1.47	0.15
EUG-14, NP-03	Landfill traffic	1.07	0.28	0.03
	Landfill bulldozing	0.58	0.15	0.02
	Byproduct drop point	0.17	0.08	0.03
Totals		13.33	6.64	1.47

Hazardous Air Pollutants (HAP)

Several AP-42 (9/98) tables list speciated emission factors for coal combustion. Table 1.1-12 presents factors for various polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans. The total of all such constituents amounts to less than 0.01 pounds per year for maximum coal consumption. Table 1.1-13 presents factors for polynuclear aromatic hydrocarbons. The total of all such constituents amounts to less than 100 pounds per year for maximum coal consumption. Table 1.1-14 presents factors for various organic compounds. The following table includes only those compounds from the Tables that are HAPs. Table 1.1-16 presents emission factors for trace elements and uses assay and other information provided by the applicant. The current table does not reflect the expected effect of the M-5 project with respect to mercury emissions. Fuel consumption for Unit 3 is 4.78×10^9 BTU/hr and 4.183×10^{13} BTU/yr or 295 TPH and 2,582,100 TPY of coal. These assumptions assure conservatively high estimates of all calculated emissions shown in the following table. The introduction to AP-42 discusses the validity of all emission factors used in the document. Quality ratings are assigned to all factors, based on validity of the test method(s) used, the number of methods used within a category, the number of facilities tested, and an assessment of variability as to specific sources within each category. An “A” is assigned to a high number of sources of the same nature, with the same or very similar test methods applied throughout. The lowest rating of “E” suggests that the test(s) used may be of questionable validity, the number of sources may be too small, and that the specific sources tested may be widely variable within the category. After the original Part 70 permit was issued, the Electric Power Research Institute (EPRI) performed a study of numerous coal-fired units and developed a handbook of factors using a model that they named PISCES. This model includes numerous site-specific factors and the facility has used it to generate a corrected emission factor of 0.0624 lbs/ton for hydrogen fluoride (HF) emissions from Unit 3. The current table does not reflect the expected effect of the TVR (M-5) project with respect to HF emissions. Hydrogen chloride is addressed individually later in this memorandum.

SPECIATED COAL COMBUSTION EMISSIONS

Chemical	Emission factor	Emissions		Factor Quality
		Lbs/hr	TPY	
Acetaldehyde	0.00057 (t)	0.34	1.47	C
Acrolein	0.00029 (t)	0.17	0.75	D
Antimony	0.93 (b)	0.01	0.04	A
Arsenic	14.75 (b)	0.14	0.62	A
Benzene	0.0013 (t)	0.77	3.36	A
Benzyl chloride	0.0007 (t)	0.41	1.81	D
Beryllium	2.59 (b)	0.02	0.11	A

Chemical	Emission factor	Emissions		Factor Quality
		Lbs/hr	TPY	
Cadmium	3.62 (b)	0.03	0.15	A
Chromium	28.72 (b)	0.27	1.20	A
Cobalt	11.38 (b)	0.11	0.48	A
Cyanide	0.0025 (t)	1.47	6.45	D
Formaldehyde	0.00024 (t)	0.14	0.62	A
Hydrogen fluoride	0.0624 (t)	36.8	161	*
Isophorone	0.00058 (t)	0.34	1.50	D
Lead	18.89 (b)	0.18	0.79	A
Magnesium	0.011 (t)	6.48	28.4	A
Manganese	76.32 (b)	0.73	3.19	A
Mercury	0.000083 (t)	0.05	0.21	A
Methyl chloride	0.00053 (t)	0.31	1.37	D
Methyl ethyl ketone	0.00039 (t)	0.23	1.01	D
Methylene chloride	0.00029 (t)	0.17	0.75	D
Nickel	25.35 (b)	0.24	1.06	A
Propionaldehyde	0.00038 (t)	0.22	0.98	D
Selenium	0.0013 (t)	0.77	3.36	A

(b) units are pounds per 10¹² BTU. (t) units are pounds per ton. * from the EPRI study

The Electric Power Research Institute (EPRI) has published the “Emission Factor Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil-Fuel-Fired Steam Electric Power Plants; 2014 Technical Report”. “Table 2-11: Average HCl Emission Values by Control Category” and “Table 2-12: Average HF Emission Values by Control Technology” include percentages of Cl and F, respectively, within subbituminous coal, emitted as HCl and HF, respectively. AEP tracks data for the average chlorine content and average fluorine content of Northeastern’s coal. These data are used to calculate the HCl and HF emission factors.

The following table shows speciated HAP emissions, with factors taken from AP-42 (4/00) Table 3.1-3 with conservatively high rates of 1.972 MMSCFH (2,011 MMBTUH, based on 1,020 BTU/SCF) for each combustion turbine and duct burner set and 30,777 MMSCFY (31,393 MMBTUY) total for all turbines and duct burners.

Pollutant	Emission Factor (lb/MMBTU)	Emissions	
		lb/hr (ea. CT & DB)	TPY (both CTs & DBs)
1,3-Butadiene	< 4.3 E-07	8.6E-04	6.7E-03
Acetaldehyde	4.0 E-05	8.0E-02	6.3E-01
Acrolein	6.4 E-06	1.3E-02	1.0E-01
Benzene	1.2 E-05	2.4E-02	1.9E-01
Ethylbenzene	3.2 E-05	6.4E-02	5.0E-01
Formaldehyde	7.1 E-04	1.4E+00	1.1E+01
Naphthalene	1.3 E-06	2.6E-03	2.0E-02
PAH	2.2 E-06	4.4E-03	3.5E-02

Propylene Oxide	< 2.9 E-05	5.8E-02	4.6E-01
Toluene	1.3 E-04	2.6E-01	2.0E+00
Xylenes	6.4 E-05	1.3E-01	1.0E+00

Two AP-42 (7/98) tables list speciated emission factors for natural gas combustion. Table 1.4-3 presents factors for organic compounds and Table 1.4-4 presents factors for metals. The following table includes only those compounds from the Tables that are HAPs. Combined gas consumption is maximized at 18,329 MMBTUH or 158,827,560 MMBTU/yr.

Pollutant	Emission factor	Emissions	
	lbs/MMCF	lbs/hr	TPY
3-Methylchloranthrene	1.8×10^{-6}	<.01	<.01
7,12-Dimethylbenz(a)anthracene	1.6×10^{-5}	<.01	<.01
Acenaphthene	1.8×10^{-6}	<.01	<.01
Acenaphthylene	1.8×10^{-6}	<.01	<.01
Benzene	2.1×10^{-3}	0.02	0.08
Benzo(a)anthrene	1.8×10^{-6}	<.01	<.01
Benzo(a)pyrene	1.2×10^{-6}	<.01	<.01
Benzo(b)fluoranthrene	1.8×10^{-6}	<.01	<.01
Benzo(g,h,i)perylene	1.2×10^{-6}	<.01	<.01
Chysene	1.8×10^{-6}	<.01	<.01
Dibenzo(a,h)anthracene	1.2×10^{-6}	<.01	<.01
Fluoranthene	3.0×10^{-6}	<.01	<.01
Fluorene	2.8×10^{-6}	<.01	<.01
Formaldehyde	7.5×10^{-2}	1.35	5.84
Hexane	1.8	15.09	64.41
Indeno(1,2,3-cd)pyrene	1.8×10^{-6}	<.01	<.01
Naphthalene	6.1×10^{-4}	<.01	0.02
Phenanthrene	1.7×10^{-5}	<.01	<.01
Pyrene	5.0×10^{-6}	<.01	<.01
Toluene	3.4×10^{-3}	0.03	0.12
Arsenic	2.0×10^{-4}	<.01	0.01
Beryllium	1.2×10^{-5}	<.01	<.01
Cadmium	1.1×10^{-3}	0.01	0.04
Chromium VI	1.4×10^{-3}	0.01	0.05
Manganese	3.8×10^{-4}	<.01	0.01
Mercury	2.6×10^{-4}	<.01	0.01
Nickel	2.1×10^{-3}	0.02	0.06
Selenium	2.4×10^{-5}	<.01	<.01

The preceding analysis does not provide an easy method of estimating HAP emissions on a facility-wide basis. The following table makes a series of conservatively high assumptions to provide a reasonable estimate at total emissions. Any pollutant with emission factors for multiple fuels is assumed to be present in the highest concentration in all fuels, and its emissions are calculated on full facility heat input. For instance, there are emission factors for formaldehyde for gas, oil, and

coal. Converted to BTU-equivalents, the highest of these is the factor of 7.1×10^{-4} lbs/MMBTU used for natural gas. This factor is applied to the facility heat input capacity of 18,329 MMBTUH and 158,827,560 MMBTU/yr. These capacities are based on the combined ratings of the turbines, HRSGs, boilers at Units 2 and 3, and the two auxiliary boilers, for the hourly rate, and all of the listed items at 8,760 hr/yr, except for the Aux 1/2 boiler, where operating hours are limited by a permit condition. When two factors exist for one fuel, dependent on the device, such as factors for natural gas at a boiler as opposed to gas at a turbine, the higher factor is assumed for all devices. The table identifies those cases in which data are taken from preceding tables by naming the single fuel controlling that choice.

Chemical	Fuel	Emissions	
		lbs/hr	TPY
1-3 Butadiene	Gas	<.01	<.01
3-Methylchloranthrene	Gas	<.01	<.01
7-12 Dimethylbenz(a)anthracene	Gas	<.01	<.01
Acenaphthene	Gas	<.01	<.01
Acenaphthylene	Gas	<.01	<.01
Acetaldehyde		1.43	6.20
Acrolein		0.33	1.43
Antimony	Coal	0.01	0.04
Arsenic		0.27	1.17
Benzene		2.57	11.1
Benzo(a)anthren	Gas	<.01	<.01
Benzo(a)pyrene	Gas	<.01	<.01
Benzo(b)fluoranthrene	Gas	<.01	<.01
Benzo(g,h,i)perylene	Gas	<.01	<.01
Benzyl chloride	Coal	0.41	1.81
Beryllium		0.05	0.20
Cadmium		0.20	0.87
Chromium		1.23	5.32
Chysene	Gas	<.01	<.01
Cobalt	Coal	0.11	0.48
Cyanide	Coal	1.47	6.45
Dibenzo(a,h)anthracene	Gas	<.01	<.01
Ethylbenzene	Gas	0.10	0.37
Fluoranthene	Gas	<.01	<.01
Fluorine	Gas	<.01	<.01
Formaldehyde		13.0	56.4
Hydrogen fluoride	Coal	16.8	73.5
Indeno(1,2,3-cd)pyrene	Gas	<.01	<.01
Isophorone	Coal	0.34	1.50
Lead		0.34	1.51
Magnesium	Coal	6.48	28.4
Manganese		1.40	6.04
Mercury*		0.09	0.40

Chemical	Fuel	Emissions	
		lbs/hr	TPY
Methyl chloride	Coal	0.31	1.37
Methyl ethyl ketone	Coal	0.23	1.01
Methylene chloride	Coal	0.17	0.75
Naphthalene	Gas	0.55	2.15
NDMA	Gas	<.01	<.01
Nickel		3.11	13.5
NMOR	Gas	<.01	<.01
PAHs	Gas	0.71	2.77
Phenanthrene	Gas	<.01	<.01
Propionaldehyde	Coal	0.22	0.98
Propylene oxide	Gas	0.11	0.45
Pyrene	Gas	<.01	<.01
Selenium	Coal	0.77	3.36
TMA	Gas	<.01	<.01
Toluene	Gas	0.51	2.00
Xylene	Gas	0.11	0.42

**Reflects theoretical estimate; the facility will comply with MATS.*

Greenhouse Gas (GHG) Emissions

Northeastern Power Station is a major source of CO₂ equivalent (GHG) emissions.

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified on Part 1b of the forms in the application and duplicated below. Appropriate recordkeeping is required for those activities indicated below with an asterisk (*) is specified in the Specific Conditions. Any Activity to which a state or federal applicable requirement applies is not insignificant even if it is included on this list.

* 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.

* 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 (NE12 emergency generator), (#2) 13,800 gallons (NE3 emergency generator), and (#3) 12,000 gallons (NE3 coal yard diesel tank). 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 is 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.

* 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.

* 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.
- 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 is 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 is 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.
- i) Spilled petroleum liquids added to the coal pile for combustion in the boilers.
- j) The fly ash material handling activities.

SECTION VII. 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. These requirements are addressed in the “Federal Regulations” section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Operating Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Part 70 Operating Permits) [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 HAPs 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 current application, from the existing Part 70 operating permit, or developed from the applicable requirement.

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 emission of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating, per Appendix C. Unit 2 predates the rule, and is considered to be existing equipment. 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 following equipment items are subject to the requirements of this subchapter.

Emission factors shown in this table reflect the factors associated with the most-polluting fuel that each item is capable of burning. Ash content of pet coke is much less than that of coal, so use of coal data is a conservatively high assumption. Compliance with these limits for Unit 3 was demonstrated by performance testing on Unit 3 for PM on March 8, 2019, and CO on October 10, 2018. Discussion of these tests is found in the “Testing” portion of Section VIII (Compliance) below.

Equipment	Maximum Heat Input (MMBTUH)	Emissions in Lbs/MMBTU	
		Appendix C	Potential
Units 1A and 1B gas turbines (ea)	1,684	0.171	0.011
Units 1A and 1B HRSGs (ea)	99	0.348	0.008
Unit 2 B&W boiler	4,754	0.125	0.008
Unit 3 C.E. boiler	4,775	0.125	0.0146 (oil)
Units 1 & 2 auxiliary boiler	220	0.288	0.008

Unit 3 auxiliary boiler	239	0.282	0.008
Units 1 & 2 3,688-hp generator	124	0.330	0.0146 (oil)
Unit 3 1,476-hp generator	50	0.410	0.0146 (oil)

Section 19-12 limits particulate emissions from new and existing emission points in an industrial process to lb/hr values determined by process weight (see Appendix G). Coal handling calculations used a control efficiency factor of 99.9%. That efficiency has been ignored for this analysis. The following table compares values calculated in Section IV above to the applicable weight-rate limitations.

Source	Emission factor, lb/ton	TPH	Emissions (lbs/hr)	
			Potential	Appendix G
Car Dumper	3.098×10^{-3}	2,835	8.78	460
Emergency Reclaim	1.033×10^{-3}	752	0.78	74
Crusher	1.033×10^{-3}	545	0.56	70
Unit 3 Silo	1.033×10^{-3}	301	0.31	63
SBC Silo 1	3.651×10^{-2}	2,625	0.18	2.625
SBC Silo 2	3.651×10^{-2}	2,625	0.18	2.625
Mill separator 1	1.714×10^{-1}	2,625	0.86	2.625
Mill separator 2	1.714×10^{-1}	2,625	0.86	2.625
Activated carbon silo	4.543×10^{-1}	0.125	0.11	1.02
Byproduct silo	1.429×10^{-3}	6,875	0.21	14.8

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
 No discharge of greater than 20% opacity is allowed except for short-term occurrences that 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 opacity exceed 60%. 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.

The Unit 3 stack is equipped with an opacity monitor, are subject to an opacity limit under NSPS Subpart D, and is exempt from Subchapter 25 opacity requirements per §25-3(a).

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 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. There is minimal vehicular traffic, and the main plant roads and main parking lots are paved. Some haul roads and the coal yard areas are not paved. Fugitive dust emissions are minimized by using water wagons on the haul roads, parking area and coal pile. Coal handling and processing areas such as the dumper building, where coal train unloading takes place, use wet spray systems, fabric filters and air handling systems to minimize fugitive dust emissions. In addition, the processing areas used in the transfer and treatment of coal are washed down with water hoses on a regular basis. Confining the active disturbance to a very small area minimizes fugitives from the coal piles. 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 hydrogen sulfide (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 comply with the following requirements:

- (1) Emission monitoring. The owner or operator shall install, calibrate, maintain, and operate a continuous SO₂ emissions monitoring system for any fossil fuel-fired steam generator that utilizes an air pollution abatement operation to reduce the emissions of sulfur oxides. Continuous monitoring of oxygen or carbon dioxide is required if it is necessary to convert SO₂ monitoring results.
- (2) Installation, calibration, maintenance, and operation of emission monitoring systems. Required emission monitoring systems shall be installed, calibrated, maintained, and operated in accordance with 40 CFR Part 60, Appendix B, and 40 CFR Part 51, Appendix P.

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. Unit 3 and auxiliary boilers 1/2 and 3 have been installed since the effective date and are new equipment. Unit 3 has SO₂ emissions of 0.0006 lbs/MMBTU from gas combustion, 0.463 lbs/MMBTU from oil combustion, and 0.717 lbs/MMBTU from coal combustion. Both auxiliary boilers have emissions of 0.0006 lbs/MMBTU from gas combustion. Thus, all units are in compliance.

OAC 252:100-33 (Nitrogen Oxides)

[Applicable]

This subchapter affects “new” combustion sources that exceed 50 MMBTUH. Limits for various fuels are set at 0.20 lbs/MMBTU for gas, 0.30 lbs/MMBTU for oil, and 0.70 lbs/MMBTU for solid fuel. Unit 3 and the auxiliary boilers have been installed since the effective date and are new equipment. NO_x emissions from the Unit 3 stack are less than the listed standards for each type of fuel. Addition of the low-NO_x burners were expected to decrease emissions below the already acceptable levels, and the refined tuning approved under C (M-6) PSD should further decrease emissions. NO_x emissions from the auxiliary boilers have a manufacturer’s suggested value of 0.12 lbs/MMBTU. Thus, all units will remain in compliance.

OAC 252:100-35 (Carbon Monoxide)

[Not Applicable]

This subchapter affects gray iron cupolas, blast furnaces, basic oxygen furnaces, petroleum catalytic cracking units, and petroleum catalytic reforming units. There are no affected sources.

OAC 252:100-37 (Volatile Organic Compounds)

[Applicable]

Part 3 requires storage tanks with a capacity of 400 gallons or more to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Fuel oil and lube oil have vapor pressures below the exemption level of 1.5 psia for VOC, per OAC 252:100-37-4(a). The 2,000-gallon gasoline tank has submerged fill. The liquid in natural gas condensate tank is

primarily water (> 99%). Therefore, the vapor pressure is well below the 1.5 psi threshold and is not subject to this part.

Part 5 limits the organic solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt per OAC 252:100-37-25(c).

Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. 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.

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

This subchapter regulates toxic air contaminants (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 recordkeeping and 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.

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

OAC 252:100-11	Alternative Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
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 a subject area
OAC 252:100-47	Municipal Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52

[Not Applicable At This Time]

This facility is a PSD-major stationary source, so emissions increases must be evaluated for PSD if they exceed a significance level (100 TPY CO, 40 TPY NO_x, 40 TPY SO₂, 40 TPY VOC, 25 TPY PM, 15 TPY PM₁₀, 10 TPY PM_{2.5}, 0.6 TPY lead). Various projects have been evaluated since the last Part 70 renewal permit was issued, but this modification does not in itself increase emissions, so no further analysis is necessary.

NSPS, 40 CFR Part 60

[Subparts A, D, Dc, GG, and OOO 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.

Subpart D (Fossil Fuel-Fired Steam Generators)

Affected sources have a design heat input capacity greater than 250 MMBTUH and must have commenced construction after August 17, 1971. The boiler associated with Unit 1 was replaced by gas turbines, although the steam turbine remains in place. Unit 2 exceeds the 250 MMBTUH threshold, but commenced construction much earlier than its start-up date of 1970, and is not an affected source. The auxiliary boiler for units 1 and 2 is rated at 220 MMBTUH, below the threshold. Thus, none of these units is an affected source.

Construction of Unit 3 and its auxiliary boiler commenced in 1974. Unit 3 was rated at 4,775 MMBTUH and was subject to this subpart. The auxiliary boiler for Unit 3 is rated at 239 MMBTUH, which is less than the threshold, and is not subject to Subpart D. Standards to be met currently by Unit 3 are as follows:

- 40 CFR §60.42 sets a particulate matter emission limit of 0.10 lbs/MMBTU and prohibits opacity in excess of 20%, except for one six-minute period per hour of not more than 27%.
- 40 CFR §60.43 sets a sulfur dioxide limit of 1.2 lbs/MMBTU for solid fuel and 0.8 lbs/MMBTU for liquid fuel, and sets a pro-ration formula for combined fuels. Compliance is based on total fuel use.
- 40 CFR §60.44 sets a nitrogen oxides limit of 0.20 lbs/MMBTU for gaseous fossil fuel, 0.30 lbs/MMBTU for liquid fossil fuel, and 0.70 lbs/MMBTU for solid fossil fuel. It also sets limits for wood residue, lignite, and combinations of these with other fuels, but this facility cannot burn such fuels. The standard is pro-rated in the instance of simultaneous combustion of different fuels.
- 40 CFR §60.45 establishes monitoring criteria, including the operation of continuous monitoring systems for opacity, sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide.
- 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 §§60.42, 60.43, and 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. Testing that demonstrated compliance was performed on March 8, 2019, and October 10, 2018, as discussed in the “Testing” portion of Section IX (Compliance) below.

Subparts Da and Db (Electric Utility and Small Steam Generating Units)

The earliest construction date under any of these subparts is September 18, 1978. Most of the steam generating units (of any size) commenced construction before this date, and they are not affected sources under either of the subparts. Combined cycle gas turbines with such capacity are affected sources only if fuel combustion in the heat recovery unit exceeds the 250 MMBTUH level. Only 99 MMBTUH is added in the HRSG, so this facility is not subject to Da or Db. Note also the following discussion of Subpart Dc.

Subpart Dc (Small Industrial-Commercial-Institutional Units)

This affects steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. The turbine project fits the definition of “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 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)).

Subparts K, Ka, Kb (Petroleum Liquid and Volatile Organic Liquid (VOL) Storage Vessels). The earliest effective date of any of these subparts is June 11, 1973. Six of the hydrocarbon storage tanks were constructed before that date and are not affected sources. Those six tanks are: #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; #10, owned by Enable Gas Services, with a capacity of 8,459 gallons of natural gas condensate; #7, with a shell capacity of 6,300 gallons, and #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 #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 #4 may have been constructed after June 11, 1973, and certainly before May 19, 1978, the pertinent dates for Subpart K. The NE12 emergency generator tank capacity of 750 bbl (31,500 gallons) of diesel is less than the 40,000-gallon threshold of 40 CFR §60.110(a), and it is not an affected source.

The new tank numbers in this paragraph are associated with the NE3 SPCC Plan. The pertinent dates for Subpart Ka are after May 18, 1978, and before July 23, 1984. Four tanks have construction dates within that period, namely: #8, with a capacity of 13,800 gallons (Unit 3 emergency generator, installed Feb. 19, 1979) and #1 - 12,000 gallon (coal yard diesel tank). PSO intends to order a replacement 12,000 coal yard fuel tank anticipated for 2021 installation. #6 and #7, each with a capacity of 13,860 gallons lube oil. Each tank capacity is less than the 40,000-gallon threshold of 40 CFR §60.110a(a), and none is an affected source.

Anything constructed after July 23, 1984, may fall within the purview of Subpart Kb. Tank #5, a 2,000-gallon gasoline tank, was constructed in 1993. Its capacity is less than the 75 m³ (19,813 gal) threshold stated in 40 CFR §60.110b(a), and the tank is not an affected source.

Subpart Y (Coal Preparation Plants). The facility handles more than 200 tons of coal per day and has coal storage systems and coal processing and conveying equipment, which are affected sources per 40 CFR §60.250(a). Construction was commenced before the effective date of October 24, 1974, given in 40 CFR §60.250(b), so Subpart Y is not applicable to this facility.

Subpart GG (Stationary Gas Turbines). This subpart affects stationary gas turbines with a heat input at peak load of greater than or equal to 10.7 gigajoules per hour (10 MMBTUH) based on the lower heating value (LHV) of the fuel and that commenced construction, reconstruction, or modification after October 3, 1977. The new 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.

Subpart KKK (Equipment Leaks of VOC from Onshore Natural Gas Processing Plants)

The facility has a tank to collect condensate but does not engage in natural gas processing.

Subpart OOO (Nonmetallic Mineral Processing Plants) affects equipment at facilities that crush or grind nonmetallic minerals, including sodium compounds. The TVR (M-5) project includes an air classifier mill that grinds sodium bicarbonate, so the related equipment will be subject to the standards of the subpart. The material will be pneumatically transferred to a storage silo, after which the entire process, including the classifier mill, is enclosed. The silo filter will be subject to an opacity limit of 7% but will be exempt from a stack concentration limit per 40 CFR §60.672(f). Compliance with the opacity standard shall be demonstrated by Reference Method 9 testing within 60 days of achieving maximum production, but no later than 180 days after first operation.

Subpart IIII (Stationary Compression Ignition Internal Combustion Engines {CI-ICE}) affects CI-ICE constructed, modified, or reconstructed after July 11, 2005. The emergency generators manufactured and went into operation prior to 2005 and are not affected facilities.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE), 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 are no affected SI engines at the facility. This subpart is not applicable.

Subpart KKKK, Stationary Combustion Turbines. This subpart affects combustion turbines with a power output at peak load of 10 MW that commence construction, modification, or reconstruction after February 18, 2005. The facility’s combustion turbines were constructed prior to February 18, 2005, and are therefore exempt.

Subpart TTTT, Greenhouse Gas Emissions for Electric Generating Units. This subpart establishes GHG standards to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of §60.5509. The GHG standards included in this subpart also apply to any steam generating unit or IGCC that commenced modification after June 18, 2014, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of §60.5509. The units at this facility pre-date the Subpart TTTT applicability dates.

NESHAP, 40 CFR Part 61

[Not Applicable]

Electric generating facilities are not an affected source under part 61.

NESHAP, 40 CFR Part 63

[Subparts ZZZZ, DDDDD, and UUUUU Applicable]

Subpart Q (Industrial Process Cooling Towers) All facilities operated by this company ceased using chrome in cooling water three decades ago.

Subpart YYYY, Stationary Combustion Turbines. This subpart, affects existing, new, or reconstructed stationary combustion turbines located at a major source of HAP emissions. There are applicable combustion turbines at this facility, since Unit 1A and Unit 1B were constructed before January 14, 2003, and are therefore defined as existing units. 40 CFR §63.6095(d) includes initial notification requirements, which PSO Northeastern has met, but these units “. . . need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.”

Subpart ZZZZ (Reciprocating Internal Combustion Engines or RICE). The two oil-fired emergency generators qualify as existing “emergency stationary RICE” per the definition found in 40 CFR §63.6675 and shall comply with this MACT per 40 CFR §63.6640(f)(1) through (f)(3).

Since EUG 16 units are existing sources located at a major source of HAPs, only the requirements in those paragraphs are applicable. Compliance with all provisions was achieved by January 31, 2016.

Subpart UUUUU (Coal- and Oil-Fired Electric Utility Steam Generating Units) affects new, reconstructed, and existing electric generating units (EGUs) that combust coal or oil. Unit 3 at Northeast is subject to the subpart, which limits the MATS MACT, that is front-half PM less than or equal to 0.0300lbs/MMBTU. Compliance with acid gas and mercury (or their surrogates) limits of the MACT shall also be required. EPA Reference Method testing shall be performed to show compliance with these limits. That project was designed to assure compliance. Discussion of the project is found in the closing paragraphs of Section II, Facility Description, and the compliance requirements were included within the TVR (M-5) permit.

Subpart JJJJJ (Industrial, Commercial and Institutional Boilers and Process Heaters) affects boilers and heaters located at, or part of, area sources of HAPs. The facility is a major source of HAP.

CAM, 40 CFR Part 64

[Applicable]

This part applies to any pollutant-specific emissions unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses “large emissions units,” or any application that addresses “large emissions units” as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant, other than an emission limitation or standard that is exempt under 40 CFR §64.2(b)(1). provisions;
- It uses a control device to achieve compliance with the applicable emission limit or standard; and,
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant that are equal to or greater than major source thresholds for that pollutant (100 TPY of criteria pollutant, or 10/25 TPY of a HAP/combination of HAPs).

Only Unit 3 has control equipment to achieve compliance with emission limits. The facility uses a positive pressure fabric filter as the control device to achieve compliance with the NSPS PM emission limitation. AEP has developed a CAM Plan for compliance with 40 CFR Part 64 for Unit 3.

CAM Plan for Fabric Filter Baghouses

I. Background

A. Emissions Units

ODEQ ID and Description: Unit 3 – Steam Generator C.E. #4974 SCRR

B. Applicable Regulation, Emission Limits, and Monitoring Requirements

Regulation: 40 CFR Part 60 Subpart D
 Particulate Mass Emissions Standard: 0.10 lb/MMBtu
 Opacity Standard: 20 percent
 Emission Limit: Particulate Mass Emissions
 Monitoring requirements: As the NSPS Subpart D regulation does not specify continuous monitoring, this CAM Plan is designed to utilize stack opacity, as measured by a certified COMS as the monitoring equipment.

C. Control Technology

Fabric filter operated under positive pressure

II. Monitoring Approach

The key elements of the monitoring approach are presented in Table 1. Note that an excursion of the upper threshold of the indicator range will occur when the 3-hour rolling average stack opacity, measured by the COMS system, exceeds 20%.

TABLE 1. MONITORING APPROACH

Indicator	Stack Opacity
I. Measurement Approach	As is the case for nearly all dry PM controls, opacity is an indicator of control device performance. An increase in opacity generally corresponds to a decrease in fabric filter performance. A certified continuous opacity monitor (COMS) has been chosen as the proposed measurement device, and stack opacity is the chosen indicator.

<p>II. Indicator Range</p>	<p>The opacity indicator range proposed for the CAM Plan is 20%. Data presented later in the plan provide justification for choosing an indicator range of 20%. The data indicates that compliance with 0.10 lb/MMBtu PM mass emissions limit is reasonably assured when stack opacity remains at 20% or lower.</p> <p><u>Monitoring Approach Justification</u></p> <p>The facility will submit periodic monitoring reports to ODEQ. A report for monitoring under 40 CFR Part 64 will include the following:</p> <ol style="list-style-type: none"> 1) Summary information on the number, duration and cause (including unknown cause, if applicable) excursions and the corrective actions taken, 2) Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than down downtime associated with zero and span or other daily calibration checks) 3) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the facility shall include in the next summary report, documentation that the implementation of the plan has been completed, and reduced the likelihood of similar levels of excursions occurring. <p>Also, PSO is proposing that if 10% or greater of the rolling 3-hour average COMS opacity values indicate excursions of the 20% opacity upper threshold of the indicator range during a calendar quarter, the facility shall develop and implement a QIP. The ODEQ may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected.</p>
<p>III. Performance Criteria A. Data Representativeness. 40 CFR §64.3(b)(1)</p>	<p>The COMS that will be utilized under this proposed CAM Plan is installed, maintained and provides data accuracy in accordance with 40 CFR Part 75, and by reference 40 CFR Part 60. The COMS is located in the unit stack, downstream of the fabric filter, in accordance with 40 CFR §60.13. The location of the installed COMS allows data representative of the fabric filter performance to be continuously monitored.</p>
<p>B. Verification of Operational Status 40 CFR §64.3(b)(2)</p>	<p>The COMS system is currently installed, certified and operational. Some software revisions may be necessary to develop 1 hour and 3 hour averaging in the system.</p>
<p>C. QA/QC Practices and Criteria 40 CFR §64.3(b)(3)</p>	<p>QA/QC of the COMS system is conducted in accordance with 40 CFR Part 75 and by reference, 40 CFR Part 60.</p>
<p>D. Monitoring Frequency 40 CFR §64.3(b)(4)</p>	<p>The COMS equipment is designed to operate continuously, except for system breakdowns, repairs, calibration checks, and zero and span adjustments. COMS data is composed of 15-second opacity readings, averaged once every six minutes, continuously.</p>

<p>IV. Data Collection Procedures</p>	<p>Generally, COMS data is expressed as 6-minute averages. The 6-minute averages are determined by averaging thirty-six 10-second periods during block 6-minute periods. The opacity data is collected and stored in the Data Acquisition System (DAS).</p>
<p>Averaging period</p>	<p>The 6-minute averages will be utilized to subsequently calculate 1-hour averages and ultimately 3-hour rolling averages. The 3-hour rolling average period has been chosen to be consistent with the averaging time of the NSPS PM mass emissions limitation.</p> <p>The plan will consider the calculated 3-hour averages to be valid if at least 50% of the possible 6 –minute averages are valid for the period.</p>

MONITORING APPROACH JUSTIFICATION

I. Background

AEP/Public Service Company of Oklahoma (PSO) believes that the continuous opacity monitoring system (COMS) data is the most appropriate and readily available indicator for continuously evaluating the performance and operations on the fabric filter and thereby assessing compliance with the applicable particulate emission rate limitation between periodic 40 CFR Part 60 Appendix A, Method 5 compliance testing. While monitoring of equipment operating parameters, such as fabric filter differential pressure and the bag protection system may be beneficial in evaluating particulate matter collection performance on a short term basis as well, this data is not continuously monitored and recorded, nor are they direct indicators of conditions in the stack prior to release of the flue gas. For these reasons, corrective actions have been identified by plant staff and developed based upon opacity monitoring.

Under this proposed Northeastern Unit 3 CAM Plan, the facility will monitor and maintain 6-minute opacity averages measured by a continuous opacity monitoring system, operated and maintained in accordance with 40 CFR Part 75 (and by reference 40 CFR Part 60), including the minimum data requirements, in order to determine 3-hour rolling average stack opacity values. The 6-minute opacity averages will be used to calculate both 1-hour block and subsequently, 3-hour rolling average opacity values. The COM QA/QC procedures will be equivalent to the applicable requirements of 40 CFR Part 75. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, but not limited to, calibration checks and required zero and span adjustments), the opacity shall be continuously monitored at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs and QA/QC activities shall not be used for purposes of 40 CFR Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement.

AEP/PSO proposes that data availability shall be at least 50% of the operating time in the 3-hour rolling averages periods to satisfy the data requirements to calculate the 3-hour average opacity. AEP/PSO also proposes that the number of invalid 3-hour periods shall not exceed 15% of the total 3-hour rolling periods during unit operation for the reporting period.

Records of the rolling 3-hour COMS opacity average and corrective actions taken during excursions of the CAM Plan indicator range shall be maintained on site and shall be made available upon request. COMS performance data will be maintained in accordance with 40 CFR Part 75 recordkeeping requirements. The facility will maintain records of monitoring data, monitor performance data, corrective actions taken in response to excursions of the upper threshold of the indicator range, any written quality improvement plan required pursuant to 40 CFR §64.8, any activities undertaken to implement a quality improvement plan, and any other supporting information required to be maintained in accordance with 40 CFR Part 64 (e.g., data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

The facility will submit periodic monitoring reports to ODEQ. A report for monitoring under 40 CFR Part 64 will include the following: 1) Summary information on the number, duration and cause (including unknown cause, if applicable) excursions and the corrective actions taken, 2) Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than down downtime associated with zero and span or other daily calibration checks), 3) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the facility shall include in the next summary report, documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions occurring.

PSO is proposing that if 10% or greater of the rolling 3-hour average COMS opacity values indicate excursions of the 20% opacity upper threshold of the indicator range during a calendar quarter, the facility shall develop and implement a QIP. The ODEQ may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected.

II. Rationale for Selection of Performance Indicators

As previously noted, opacity measured by a continuous opacity monitoring system has been selected as the performance indicator. Stack opacity, downstream of the control system, is generally indicative of good operation and maintenance of the fabric filter. When the fabric filter controls are operating optimally, there will be little visible particulate matter emissions at the stack outlet. In general, an increase in opacity indicates reduced performance of the fabric filter. Reduced performance can be caused by loose or torn bags or other problems. In addition to the PM mass emissions limit that this CAM Plan is intended to monitor, Unit 3 is also subject to an NSPS opacity standard of 20 percent.

III. Rationale for Selection of Indicator Ranges

The indicator range for opacity is a 6-minute block average opacity of 20 percent. As previously mentioned, the 6-minute average data will be averaged to calculate 1-hour block averages. Subsequently, 3-hour rolling averages will be developed. The 20% opacity indicator range was selected based on the facility's permit requirements and historical stack test data.

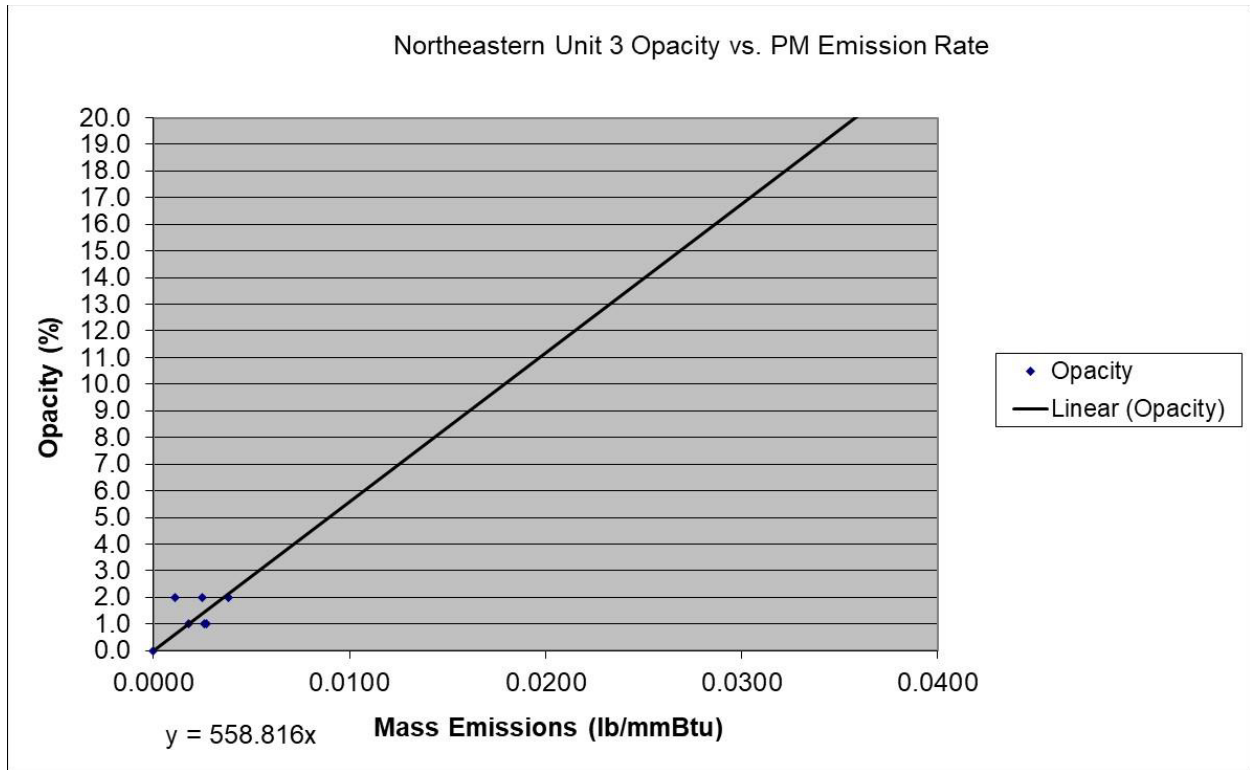
The two most recent PM mass emissions performance tests, using compliance test methods (RM 5) for Title V compliance, were conducted on March 8, 2019 and on October 20, 2021. The measured PM-filterable emissions during each of the test runs conducted during these two tests were extremely low with each run indicating particulate mass emissions less than 4% of the NSPS

standard. COMS readings during the testing were also consistently low, with a maximum of 2.0%. Complete test results were documented in the test report provided by AEP-United Sciences Testing, Inc. and are available by request. The data for each of these tests is presented in graphical format below and provides a strong indication that at 20% opacity, the Unit 3 PM mass emissions are well below the NSPS PM limitation of 0.10 lb/MMBtu. As future PM mass emissions stack tests are completed as a demonstration of compliance with the 0.10 lb/MMBtu NSPS limit, data from these test runs will be used to supplement the data represented at the back of this document and used to confirm continued appropriateness of the 20% opacity upper threshold of the indicator range.

Also, it may be noted that using Bouger’s Law correlation (Continuous Emission Monitoring (James A. Jahnke, Second Edition, March 2000)), at 2% opacity and .0038 lb/mmbtu test results, opacity would be 41% at 0.1 lb/mmbtu. This is further justification that 20% opacity provides assurance of compliance.

HISTORICAL BASELINE DATA USED TO ESTABLISH INDICATOR RANGE

Date	Mass	Opacity
3/8/2019	0.0018	1.0
	0.0026	1.0
	0.0027	1.0
10/20/2021	0.0038	2.0
	0.0025	2.0
	0.0011	2.0
Zero Point	0.0000	0.0



RESPONSE TO EXCURSION

In accordance with the proposed CAM Plan, an excursion of the upper threshold of the indicator range will occur when the 3-hour rolling average stack opacity, measured by the COMS system, exceeds 20%. An excursion of this indicator threshold does not indicate conclusively that an exceedance of the NSPS particulate matter mass emission limit (0.10 lb/MMBtu) has occurred, as evidenced by the data presented below. However, an excursion of the indicator threshold will prompt plant staff to take actions to determine the reason for the elevated opacity levels and implement corrective actions to reduce opacity. The corrective actions will be implemented any time there is a short duration or sustained duration increase in opacity above the upper threshold value of the indicator range. Upon a short duration increase of stack opacity above the upper threshold of the indicator range (20% opacity), plant staff will continue to observe the COMS data and simultaneously begin investigating potential causes for the opacity increase. Information reviewed can include fabric filter performance data as well as unit operating parameters and verification of COMS accuracy.

Upon detection of an excursion (3 hours or more) under the CAM Plan, plant staff will continue to work to restore operation of unit (including the PM control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response may include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operations. Actions may include initial evaluation of operating parameters, noting that operations have returned to normal without operator action or any necessary follow up actions to return operation to within the indicator range. If the stack opacity level continues to exceed the upper threshold value (20%) of the indicator range after corrective

actions have been implemented, plant operations staff will contact appropriate management staff or system control staff to obtain necessary approvals to reduce load, or in extreme cases, commence a unit shutdown in order to remediate the cause of the opacity increase. In the case of a necessary shutdown, the shutdown of the unit will be scheduled and executed in a safe, expedient and effective manner, while maintaining the integrity of the generating unit and electrical grid system.

EXCLUSION OF AN INSPECTION/MAINTENANCE (I/M) PROGRAM FROM CAM

After reviewing the CAM regulation, AEP/PSO have elected not to include an inspection and maintenance program as an indicator in our monitoring plan for PSO Northeastern Unit 3. The language below is taken directly from the CAM regulation. The regulation states that the owner/operator shall design the plan based on one or more indicators. The rule references the fact that opacity or recorded findings of inspection and maintenance activities (among other indicators of performance) can be chosen as an indicator. However, the rule does not specify that I/M must be chosen as an indicator. As discussed in our meeting last week with ODEQ, the CAM regulation does not require that more than one indicator be used as part of the CAM Plan design.

§ 64.3 Monitoring design criteria.

(a) General criteria. To provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit, monitoring under this part shall meet the following general criteria:

*(1) The owner or operator shall design the monitoring to obtain data for one or more indicators of emission control performance for the control device, any associated capture system and, if necessary to satisfy **paragraph (a)(2)** of this section, processes at a pollutant-specific emissions unit. Indicators of performance may include, but are not limited to, direct or predicted emissions (including visible emissions or opacity), process and control device parameters that affect control device (and capture system) efficiency or emission rates, **or recorded findings of inspection and maintenance activities** conducted by the owner or operator.*

The PSO Northeastern Unit 3 CAM Plan relies on opacity (as measured by COMS) as our chosen indicator. The used of a certified COMS monitor is a presumptively acceptable monitoring system under the CAM regulation.

In researching this subject, we actually noted that EPA specifically addressed the question related to Inspection and Maintenance in their Response to Comments for the CAM rule (dated October 2, 1997). The comment and associated response is pasted below and confirms that an inspection and maintenance program is allowed as a monitoring approach, but it is not one that the owner/operator is compelled to use.

6.1.4: Use of Maintenance Records as Part of Monitoring

Comment a: One commenter argued that CAM should not require the keeping of maintenance records for compliance purposes. To the extent that proposed 40 CFR §64.6(a) and (b) compel the maintaining of maintenance records for determination of compliance, the commenter stated that

they are beyond the logical reach of Section 114 of the Clean Air Act. The commenter argued that maintenance records are kept for repair purposes, not monitoring purposes.

Response: The provisions in § 64.6(a)(1) of the final rule allow an owner or operator to propose monitoring that includes as at least one component of the monitoring approach the "recorded findings of inspection and maintenance activities."

The rule thus does not compel the I/M approach as suggested in the comment.

Chemical Accident Prevention Provisions, 40 CFR Part 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 from the web page: <https://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. 2019-0782-ARR4 was issued in January 2020, 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. 2019-0782-ARR4.

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. 2019-0782-ARR4 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 [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.

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.

The standard conditions of the permit address the requirements specified at § 82.156 for persons opening appliances for maintenance, service, repair, or disposal; § 82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; § 82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; § 82.166 for recordkeeping; § 82.158 for leak repair requirements; and § 82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part. Certified facility personnel perform services on heavy mobile equipment that involve ozone-depleting substances. Motor vehicles are serviced at a local third-party garage by its certified technicians. A certified contractor is used to service all stationary air-conditioning units located on site. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION IX. COMPLIANCE

The Specific Conditions of this permit contain various testing, monitoring, recordkeeping, and reporting requirements in order to document on-going compliance with emission limits. The specific method used to document compliance was based on the type of emission unit, the type of process equipment, the specific pollutants emitted, and the amount of permitted emissions taking into account other regulatory requirements that an emission unit may be subject to.

In addition to the permitting requirements, the following periodic inspections were conducted since issuance of the last Title V renewal permit.

Inspection Type	Date	Summary/Results
Full Inspection	2/20/20	In Compliance
Full Inspection	3/24/2019	In Compliance
Full Inspection	3/14/2018	In Compliance
Full Inspection	5/17/2017	Failed to monitor Opacity from Unit 3 during the 4 th quarter of 2016.
Full Inspection	4/06/2016	In Compliance
Full Inspection	4/30/2015	In Compliance

There have been no enforcement actions since issuance of the last Title V renewal permit.

SECTION XI. TIER CLASSIFICATION, PUBLIC AND EPA REVIEW

Tier Classification

This application has been classified as **Tier II** based on the request for a renewal of a Part 70 operating permit. Public review and EPA review for the permit is required. 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 application involves only land owned by the applicant.

Fees Paid

Part 70 operating permit renewal fee of \$7,500 has been received.

Public Review

The applicant published the “Notice of Filing a Tier II Application” in *The Tulsa World*, a daily newspaper of general circulation in Tulsa, Oklahoma on May 26, 2022. The notice stated that the application was available for public review at the Will Rogers library, 1515 N. Florence Avenue, Claremore, Oklahoma 74017, and at the Air Quality Division’s main office in Oklahoma City, Oklahoma. The application was also available for public review on the Air Quality section of the DEQ web page at <https://www.deq.ok.gov>.

The applicant will also publish the “Notice of Tier II Draft Permit” in a newspaper in the county where the facility is located. The notice will state that the draft permit (when ready) will be available for public review at a local public library and at the Air Quality Division’s main office in Oklahoma City, Oklahoma. The draft permit will also be available for public review on the Air Quality section of the DEQ web page at <https://www.deq.ok.gov>. The draft permit will be available for public review for a period of 30-days.

Neighboring States

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

EPA Review

After public review, the draft permit will be forwarded to EPA Region VI for a 45-day review period. The information on all permit actions is available for review by the public in the Air Quality section of the DEQ web page at <https://www.deq.ok.gov>.

Public Petition

If the Administrator does not object in writing during the 45-day EPA review period, any person that meets the requirements of OAC 252:100-8-8(j) may petition the Administrator within 60 days after the expiration of the Administrator's 45-day review period to make such objection. Any such petition shall be based only on objections to the permit that the petitioner raised with reasonable specificity during the public comment period provided for in 27A O.S. § 2-14-302.A.2., unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period. If the Administrator objects to the permit as a result of a petition filed under OAC 252:100-8-8(j), the DEQ shall not issue the permit until EPA's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and prior to an EPA objection. If the DEQ has issued a permit prior to receipt of an EPA objection under OAC 252:100-8-8(j), the DEQ will modify, terminate, or revoke such permit, and shall do so consistent with the procedures in 40 CFR §§ 70.7(g)(4) or (5)(i) and (ii) except in unusual circumstances. If the DEQ revokes the permit, it may thereafter issue only a revised permit that satisfies EPA's objection. In any case, the source will not be in violation of the requirement to have submitted a timely and complete application.

Testing

The results of the Performance Testing were conducted on Northeastern Unit 3 for PM on March 8, 2019, and CO on October 10, 2018, are as follows:

TEST RESULTS

Test Location	Test Parameter	Emission Limit (lb/MMBTU)	Emission Rate (lb/MMBTU)
Unit 3 Stack	CO	0.53	0.177
	PM _{filterable}	0.03	0.0024
	PM _{condensable}	0.10	0.0023
	VE	20%	0.0%

SECTION X. SUMMARY

The applicant has demonstrated compliance with all 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, which would prevent issuance of this permit. Issuance of the permit is recommended, contingent on public and EPA review.

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

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

Permit Number 2019-0607-TVR3

The permittee is authorized to operate in conformity with the specifications submitted to Air Quality on May 17, 2019. The Evaluation Memorandum dated May 18, 2022, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emission limitations for each point. Where these limitations conflict with those of Specific Condition No. 5 below, the more stringent limitation applies.

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

A. EUG 1

Gas Turbines and Heat Recovery Steam Generators (HRSG)

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
1	1A	GE MS7001FA S/N 297510	160	1,684*	Jan. 2000
1	1B	GE MS7001FA S/N 297511	160	1,684*	Jan. 2000

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 original steam turbine.

* Under certain operating conditions, the heat input of each turbine may be increased to 1903 MMBTUH.

Each Combustion Turbine without Duct Burners

Pollutant	lbs/hr	TPY	ppmvd ⁽¹⁾
NO _x	108	418	15
SO ₂	1.18	5.19	
PM ₁₀ ²	20.9	81.1	
VOC	0.40	1.49	
CO	51.7	198	12
H ₂ SO ₄	0.06	0.24	

⁽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.

⁽²⁾ Total PM (front and back halves).

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.

Each Combustion Turbine with Duct Burners

Pollutant	lbs/hr	TPY
NO _x	117	457
SO ₂	1.26	5.50
PM ₁₀ *	21.9	85.5
VOC	0.50	1.92
CO	60.6	237
H ₂ SO ₄	0.06	0.25

* Total PM (front and back halves).

Compliance with these emission limits 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.

B. EUG 2

Unit #2 is no longer a “grandfathered” unit, and is subject to emission limits for CO and NO_x. The BACT emission limit is 0.148 lbs/MMBTU for CO, 3-hour average. The NO_x limit is 0.28 lbs/MMBTU, rolling 30-calendar day average. CO compliance shall be demonstrated by Reference Method testing once every four operating quarters, as defined in 40 CFR Part 75.

EUG 2 Grandfathered Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const Date
2	2	Babcock and Wilcox UP-60	495	4,754	Mar, 1970

C. EUGs 3, Aux 3, 6-9, and Coal Pile

EUG 3 Steam Generator

EU	Point	Make/Model	MW-Gross	MMBTUH	Const/Mod Date
3	3	Combustion Engineering #4974 SCRR	490	4,775	Apr, 1974/June 2015

EUG Aux 3 Steam Generator

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 3	Aux 3	Combustion Engineering #3M1004	N/A	239	Apr, 1974

For Unit 3, the CO BACT emission limit is 0.530 lbs/MMBTU 3-hour average, demonstrated by Reference Method testing once every four operating quarters, as defined in 40 CFR Part 75. The NO_x limit is 0.15 lbs/MMBTU, rolling 30-calendar day average when firing 100% on coal. The NSPS Subpart D limits are shown in the following table.

NSPS Subpart D Limits

Source	Pollutant	Lbs/MMBTU
Unit 3	PM	0.1*
	SO ₂	1.2
	NO _x	0.7

* NSPS limit measured as filterable (front half) only.

These limits derive from the original construction permit, with the NO_x datum updated to reflect Acid Rain Permit requirements. The 0.7 lbs NO_x/MMBTU emissions represent a NSPS three-hour rolling average limit. As of April 16, 2016, Unit #3 has been subject to the limits of the MATS MACT, that is front-half PM less than or equal to 0.03 lbs/MMBTU. Compliance with acid gas and mercury (or their surrogates) limits of the MACT shall also be required. The SO₂ limit is 0.4 lb/MMBTU, and the mercury limit is 1.2 lb/MMBTU, and each are 30-day rolling averages. EPA Reference Method testing shall be performed to show compliance with these limits.

EUG 6A & 6B Rotary Car Dumper Baghouses (East and West)

EU	Point	Make/Model	Const Date
6	6A & 6B	Peabody #03-21	Apr, 1974

EUG 7 Emergency Reclaim Water Curtain

EU	Point	Make/Model	Const/Mod Date
7	7	Engart	July 2009

EUG 8 Crusher House Water Curtain

EU	Point	Make/Model	Const/Mod Date
8	8	Engart	July 2009

EUG 9 Unit 3 Coal Silo (Cascade) Dust Collector

EU	Point	Make/Model	Const Date
9	9	Peabody #D2-10	Apr, 1974

EUG Coal Pile

This covers fugitive emissions from wind erosion of the coal pile.

EU	Point	Make/Model	Const Date
--	--	Coal Pile	Apr, 1974

D. EUG Aux 1/2 Steam Generator

EU	Point	Make/Model	MW	MMBTUH	Const Date
Aux 1/2	Aux 1/2	Babcock and Wilcox FM 117-97	N/A	220	Mar 1997

AUXILIARY BOILER 1/2 EMISSIONS

Pollutant	Lbs/hr	TPY
TSP = PM ₁₀	1.64	0.72
SO ₂	0.13	0.06
NO _x	41.0	18.0
CO	18.1	7.94
VOC	1.19	0.52

E. EUG 11 - 15 Fugitive emissions are estimated based on existing equipment items but do not have a specific limitation.

EUG 11 Coal Handling Fugitives**EUG 12 Fly Ash Handling Fugitives****EUG 13 Bottom Ash Handling Fugitives****EUG 14 Byproduct Handling Fugitives****EUG 15 Bin Vent Filters***

EU	Point	Source	Const Date
15	1	Sorbent silo 1	Feb. 2016
15	2	Sorbent silo 2	Feb. 2016
15	3	Activated carbon silo	Feb. 2016
15	4	Byproduct silo	Feb. 2016
15	5	Classifier mill 1	Feb. 2016
15	6	Classifier mill 2	Feb. 2016

**Authorized under the TVR (M-5) permit and completed on Feb. 2016.*

These filters are process equipment designed to retain product, secondarily acting as pollution control devices.

F. EUG 16 Emergency Engines (for Emergency Generators)

EU	HP	Description	Fuel Type	Function	Mfg. Date
GEN 1/2	3,600	General Motors, Model MP45A	Diesel	for Units 1 & 2	05/1968
GEN 3	1,476	Detroit Diesel Allison, Model 16V-149T	Diesel	for Unit 3	02/1979

The engine shall be operated as follows.

- a. The owner/operator shall comply with this NESHAP Subpart ZZZZ (40 CFR §63.6640(f)).
- b. The engine shall be fueled with diesel with a maximum sulfur content of 0.0015% by weight.

- c. The operating hours for each emergency engine shall be limited to 100 hours/year for maintenance, testing, emergency demand response, and deviation of voltage or frequency of 5% or greater from standard voltage or frequency.
- d. There is no time limit on the use of emergency stationary RICE in emergency situations.

F. EUG ChemStore and Plantwide. These sources are not subject to permitting and no emissions are calculated or authorized.

EUG ChemStore Stored Chemicals

This EUG covers various stored chemicals, including hydrogen and ammonia.

EUG Plantwide Entire Facility

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

2. All limits in Specific Condition 1 apply to Unit 2 while operating 100% on natural gas, and to Unit 3 while operating 100% on coal. Auxboiler 3 operates under a 10% annual capacity factor, and annual natural gas consumption shall not exceed 209,364 MMBTU/YR. Unit 3 is primarily coal-fired, with natural gas, #2 fuel oil, and co-firing of coal and natural gas as secondary fuels. The flexibility of using those secondary fuels is implied only for Unit 3.

The permittee may operate individual units as appropriate. Emission calculations shall use the best available source, such as current 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 word "coal" includes the use of petroleum coke (pet coke) as an alternate or blended fuel. CEM data shall be used to demonstrate that the SO₂ limit of Specific Condition #1 is not exceeded while pet coke is being used.

Compliance with the authorized emission limits for Auxboiler 1/2 shall be demonstrated by fuel usage. Annual natural gas consumption shall not exceed 192,720 MMBTU/YR (equivalent to a 10% annual capacity factor) for Auxboiler 1/2.

3. The permittee shall be authorized to operate this facility 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 SO₂ allowances.
 - b. Report quarterly emissions to EPA per 40 CFR Part 75.
 - c. Conduct RATA tests per 40 CFR Part 75.
 - d. Updated QA/QC plan for maintenance of the CEMS.
5. The boiler at Unit 3 is subject to NSPS Subpart D and shall satisfy the following. [40 CFR Part 60, Subpart D]

- a. Particulate matter emissions shall not exceed 0.10 lbs/MMBTU.
 - b. Opacity shall not exceed 20%, except for one six-minute period per hour of not more than 27%.
 - c. Sulfur dioxide emissions shall not exceed 1.2 lbs/MMBTU for solid fuel and 0.8 lbs/MMBTU for liquid fuel, with a pro-ration formula for combined fuels. Compliance is based on total fuel use.
 - d. Nitrogen oxides emissions shall not exceed 0.20 lbs/MMBTU for gaseous fossil fuel, 0.30 lbs/MMBTU for liquid fossil fuel, and 0.70 lbs/MMBTU for solid fossil fuel. The standard is pro-rated in the instance of simultaneous combustion of different fuels.
 - e. Monitoring criteria include the operation of continuous monitoring systems for opacity, sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide.
 - f. 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.
 - g. The continuous emissions monitoring system (CEMS) installed to demonstrate compliance with 40 CFR Part 75 may be used to satisfy (e) and (f).
6. The permittee shall at all times properly operate and maintain all boilers and associated emissions control systems in a manner that will minimize emissions of hydrocarbons or other organic materials.
[OAC 252:100-37-36]
7. The permittee shall not replace the modified burners on Unit 2, or the low-NO_x concentric firing systems of Unit 3.
[OAC 252:100-43]
8. The permittee shall utilize a portable baghouse or equivalent control to reduce opacity of emissions during off-line sandblasting of the ESP and/or boiler at Unit 3.
[Consent Order 06-316]
9. Performance testing to establish PM₁₀ emissions from Unit 3 shall be performed every other year. Appropriate Reference Method testing to determine that filterable (front half) emissions are in compliance with the Subpart D standard of 0.10 lb/MMBTU and that combined filterable and condensable (back half) emissions are in compliance with the OAC 252:100-19 standard of 0.125 lbs/MMBTU shall be used. Testing shall be performed in a timely manner such that results of the performance tests and opacity readings taken during the tests can be provided with the Title V renewal application.
[OAC 252:100-43]
10. The turbines are subject to federal New Source Performance Standards, 40 CFR Part 60, Subpart GG, and shall comply with all applicable requirements.
[40 CFR Part 60, Subpart GG]
- a. 60.332: Standard for nitrogen oxides
 - b. 60.333: Standard for sulfur dioxide
 - c. 60.334: Monitoring of operations
 - d. 60.335: Test methods and procedures
11. Unit 3 is subject to NESHAP Subpart UUUUU and shall comply with all requirements of the subpart, including construction of the project, monitoring, reporting, and recordkeeping.

[40 CFR Part 63 Subpart UUUUU, 40 CFR §63.6(i)(4)(i)(A)]

- (a) §63.9980 What is the purpose of this subpart?
- (b) §63.9981 Am I subject to this subpart?
- (c) §63.9982 What is the affected source of this subpart?
- (d) §63.9983 Are any EGUs not subject to this subpart?
- (e) §63.9984 When do I have to comply with this subpart?
- (f) §63.9985 What is a new EGU?
- (g) §63.9990 What are the subcategories of EGUs?
- (h) §63.9991 What emission limitations, work practice standards, and operating limits must I meet?
- (i) §63.10000 What are my general requirements for complying with this subpart?
- (j) §63.10001 Affirmative defense for exceedance of emission limit during malfunction.
- (k) §63.10005 What are my initial compliance requirements and by what date must I conduct them?
- (l) §63.10006 When must I conduct subsequent performance tests or tune-ups?
- (m) §63.10007 What methods and other procedures must I use for the performance tests?
- (n) §63.10008 [Reserved]
- (o) §63.10009 May I use emissions averaging to comply with this subpart?
- (p) §63.10010 What are my monitoring, installation, operation, and maintenance requirements?
- (q) §63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?
- (r) §63.10020 How do I monitor and collect data to demonstrate continuous compliance?
- (s) §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?
- (t) §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?
- (u) §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?
- (v) §63.10030 What notifications must I submit and when?
- (w) §63.10031 What reports must I submit and when?
- (x) §63.10032 What records must I keep?
- (y) §63.10033 In what form and how long must I keep my records?
- (z) §63.10040 What parts of the General Provisions apply to me?
- (aa) §63.10041 Who implements and enforces this subpart?
- (bb) §63.10042 What definitions apply to this subpart?

12. All boilers and process heaters, with the exception of Units 2 and 3, are subject to NESHAP Subpart DDDDD, and shall comply with all requirements of the subpart no later than January 31, 2016. [40 CFR Part 63 Subpart DDDDD]

§ 63.7480, 7485, 7490, 7491, 7495 What This Subpart Covers

§ 63.7499, 7500, 7501	Emission Limitations and Work Practice Standards
§ 63.7505	General Compliance Requirements
§ 63.7510, 7515, 7520, 7521, 7522, 7525, 7530, 7533	Testing, Fuel Analyses, and Initial Compliance Requirements
§ 63.7535, 7540, 7541	Continuous Compliance Requirements
§ 63.7545, 7550, 7555, 7560	Notification, Reports, and Records
§ 63.7565, 7570, 7575	Other Requirements and Information
Tables 1 through 13	

13. The sodium bicarbonate transportation, storage, and grinding systems are subject to NSPS Subpart OOO. The systems shall comply with all applicable requirements.

[40 CFR Part 60, Subpart OOO]

§ 60.670	Applicability and designation of affected facility.
§ 60.671	Definitions.
§ 60.672	Standard for particulate matter (PM).
§ 60.673	Reconstruction.
§ 60.674	Monitoring of operations.
§ 60.675	Test methods and procedures.
§ 60.676	Reporting and recordkeeping.
Table 1	Exceptions to applicability of Subpart A.
Table 2	Stack emission limits
Table 3	Fugitive emission limits

14. Unit 3 of the facility is subject to Compliance Assurance Monitoring (CAM) and shall comply with the following requirements.

[40 CFR Part 64]

TABLE 1. MONITORING APPROACH

Indicator	Stack Opacity
I. Measurement Approach	As is the case for nearly all dry PM controls, opacity is an indicator of control device performance. An increase in opacity generally corresponds to a decrease in fabric filter performance. A certified continuous opacity monitor (COMS) has been chosen as the proposed measurement device, and stack opacity is the chosen indicator.
II. Indicator Range	<p>The opacity indicator range proposed for the CAM Plan is 20%. Data presented later in the plan provide justification for choosing an indicator range of 20%. The data indicates that compliance with 0.10 lb/MMBtu PM mass emissions limit is reasonably assured when stack opacity remains at 20% or lower.</p> <p><u>Monitoring Approach Justification</u></p> <p>The facility will submit periodic monitoring reports to ODEQ. A report for monitoring under 40 CFR Part 64 will include the following:</p> <p>1) Summary information on the number, duration and cause (including unknown cause, if applicable) excursions and the corrective actions taken,</p>

Indicator	Stack Opacity
	<p>2) Summary information on the number, duration, and cause (including unknown cause, if applicable) for monitor downtime incidents (other than down downtime associated with zero and span or other daily calibration checks)</p> <p>3) A description of the actions taken to implement a quality improvement plan (QIP) during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the facility shall include in the next summary report, documentation that the implementation of the plan has been completed, and reduced the likelihood of similar levels of excursions occurring.</p> <p>Also, PSO is proposing that if 10% or greater of the rolling 3-hour average COMS opacity values indicate excursions of the 20% opacity upper threshold of the indicator range during a calendar quarter, the facility shall develop and implement a QIP. The ODEQ may waive this QIP requirement upon a demonstration that the cause(s) of the excursions have been corrected.</p>
<p>III. Performance Criteria A. Data Representativeness. 40 CFR §64.3(b)(1)</p>	<p>The COMS that will be utilized under this proposed CAM Plan is installed, maintained and provides data accuracy in accordance with 40 CFR Part 75, and by reference 40 CFR Part 60. The COMS is located in the unit stack, downstream of the fabric filter, in accordance with 40 CFR §60.13. The location of the installed COMS allows data representative of the fabric filter performance to be continuously monitored.</p>
<p>B. Verification of Operational Status 40 CFR §64.3(b)(2)</p>	<p>The COMS system is currently installed, certified and operational. Some software revisions may be necessary to develop 1 hour and 3 hour averaging in the system.</p>
<p>C. QA/QC Practices and Criteria 40 CFR §64.3(b)(3)</p>	<p>QA/QC of the COMS system is conducted in accordance with 40 CFR Part 75 and by reference, 40 CFR Part 60.</p>
<p>D. Monitoring Frequency 40 CFR §64.3(b)(4)</p>	<p>The COMS equipment is designed to operate continuously, except for system breakdowns, repairs, calibration checks, and zero and span adjustments. COMS data is composed of 15-second opacity readings, averaged once every six minutes, continuously.</p>
<p>IV. Data Collection Procedures</p>	<p>Generally, COMS data is expressed as 6-minute averages. The 6-minute averages are determined by averaging thirty-six 10-second periods during block 6-minute periods. The opacity data is collected and stored in the Data Acquisition System (DAS).</p>
<p>Averaging period</p>	<p>The 6-minute averages will be utilized to subsequently calculate 1-hour averages and ultimately 3-hour rolling averages. The 3-hour rolling average period has been chosen to be consistent with the averaging time of the NSPS PM mass emissions limitation.</p> <p>The plan will consider the calculated 3-hour averages to be valid if at least 50% of the possible 6 –minute averages are valid for the period.</p>

- A. §64.1: Definitions.
- B. §64.2: Applicability.
- C. §64.3: Monitoring design criteria.
- D. §64.4: Submittal requirements.
- E. §64.5: Deadlines for submittals.
- F. §64.6: Approval of monitoring.
- G. §64.7: Operation of approved monitoring.
- H. §64.8: Quality improvement plan (QIP) requirements.
- I. §64.9: Reporting and recordkeeping requirements.
- J. §64.10: Savings provisions.

15. The following records shall be maintained on-site. All such records shall be made available to regulatory personnel upon request. These records shall be maintained for a period of at least five years after the time they are made. [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. Operations and maintenance log for Unit 2 sufficient to demonstrate compliance with Specific Condition #7.
- e. Maintenance and visual inspection of particulate filter systems (weekly).
- f. Pressure drop or manufacturer's recommendation for the Unit 3 fabric filter.
- g. Hours each CT spends in start-up and in shutdown, as required by Specific Condition #1 (A) EUG 1.
- h. Data demonstrating compliance with NSPS Subpart GG, as required by Specific Condition # 10.
- i. Records required by NESHAP Subpart UUUUU, per SC #11.
- j. Records required by NESHAP Subpart DDDDD, per SC #12.
- k. Records required by NSPS Subpart OOO, per SC #13.
- l. Records required by NSPS Subpart D, per SC #5.
- m. Records required by 40 CFR Part 64, per SC #14.
- n. Operating hours of each emergency generator (monthly and 12-month rolling total).
- o. Records required under 40 CFR §63.6640(f), per SC #1.E EUG 16.
- p. Records required by SC #17.
- q. Records required by SC #21.

16. The following records shall be maintained on-site 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. Gallons of spilled petroleum liquids added to the coal pile.
- d. Amount and disposition of fly ash handled by the ash management contractor.

- e. 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.
- f. Vapor pressure of the drip in the Unit 1 and 2 Gas Yard’s Condensate Drip Tank.

17. The boilers in EUG 2 and 3 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and 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.

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
2	2	Babcock and Wilcox UP-60	4,754	1970
3	3	Combustion Engineering #4974 SCRR	4,775	1974

- b. The permittee shall maintain the Low-NO_x burners, overfire air and ESP (or primary particulate matter control device) 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.

EU ID#	Point ID#	NO _x	Averaging Period
2	2	0.28 lb/MMBTU	30-day rolling

EU ID#	Point ID#	NO _x ¹ Emission Limit	Averaging Period
3	3	0.15 lb/MMBTU	30-day rolling

¹Limits apply only when units are firing 100% on coal.

EU ID#	Point ID#	PM ₁₀ Emission Limit	Averaging Period	Combined Annual Emission Rate
3	3	0.10 lb/MMBTU	3-hour	2,092 TPY 12-month rolling

EU ID#	Point ID#	SO ₂ Emission Limit	Averaging Period	Annual Emission Rate
3	3	0.40 lb/MMBTU	30-day rolling	8,366 TPY 12-month rolling
		1,910 lb/hr		

- d. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da. [OAC 252:100-8-6(a)]

18. The RHA will require that beginning in calendar year 2021, 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 the operating coal-fired generating unit at Northeastern Station will be reduced as follows:

- (i). to no more than 70 percent in calendar years 2021 and 2022;
- (ii). to no more than 60 percent in calendar years 2023 and 2024; and
- (iii). to no more than 50 percent in calendar years 2025 and 2026.

19. Reasonable precautions shall be taken to minimize fugitive dust emissions from all activities. These precautions shall include, but not be limited to: [OAC 252:100-29]

- (i) Use of water or chemicals on roads, stockpiles, material processing and transfer operations.
- (ii) Apply coatings or coverings to substances susceptible to becoming air-borne or wind-borne.
- (iii) Cover or wet material in trucks.
- (iv) Plant and maintain vegetation coverings or windbreaks.
- (v) Locate stockpiles so as to provide minimum exposure to high wind and avoid open spaces near neighboring homes or businesses.
- (vi) Curtail operations as required to comply with emission limitations.

20. 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)]

21. 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)]

22. This permit supersedes all previous Air Quality operating permits for this facility, which are now canceled, with the exception of Acid Rain Renewal Permit No. 2019-0782-ARR4.

**MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)**

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 C.F.R. §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, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. 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), 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 (“NESHAPs”) 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 C.F.R. §§60.7 and 63.10, 40 CFR Parts 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 C.F.R. Part 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. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [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. The affirmative defense of emergency 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, the DEQ, and the EPA 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 C.F.R., 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 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 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 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. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

- (1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
- (2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
- (3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
- (4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R. § 70.8(a) and (c).
- (5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
- (6) The DEQ complies with 40 C.F.R. § 70.8(d).
- (7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
- (8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
- (9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

- (10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. 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]



PART 70 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-TVR3

American Electric Power,

having complied with the requirements of the law, is hereby granted permission to operate the Public Service Company of Oklahoma Northeastern Power Station, located in Section 4, T22N, R15E, one mile south of Oologah, Rogers County, Oklahoma, subject to standard conditions dated June 21, 2016, and specific conditions, both attached.

This permit shall expire five (5) years from the issuance date below, except as authorized under Section VIII of the Standard Conditions.

DRAFT

Kendal Stegmann, Division Director

Issuance Date

Attn: Daryll Jackson, VP, PSO Generating Assets
American Electric Power
P.O. Box 399
Oologah, OK 74053

Re: Permit Application No. **2019-0607-TV R3**
PSO Northeastern Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Permit Writer: Iftekhar Hossain

Dear Mr. Jackson:

Enclosed is the permit authorizing operation of the referenced facility. 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 in this matter. If we may be of further service, or you have any questions about this permit, please contact the permit writer at Iftekhar.hossain@deq.ok.gov or me at (405) 702-4100.

Sincerely,

DRAFT

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

Enclosures

Kansas Department of Health & Environment
1000 SW Jackson, Suite 310
Topeka, Kansas 66612-1366

Re: Permit Application No. **2019-0607-TVR3**
PSO Northeastern Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Permit Writer: Iftekhar Hossain

Dear Sir / Madame:

The subject facility has requested a Title V operating permit under 40 CFR Part 70. 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 proposed permit will be provided to you upon request. Information on all permit and a copy of this draft permit are available for review by the public in the Air Quality Section of DEQ Web Page: <https://www.deq.ok.gov>.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or contact the permit writer at Iftekhar.hossain@deq.ok.gov or me at (405) 702-4100.

Sincerely,



Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

May 31, 2022

Cherokee Nation
Attn: Chuck Hoskin, Jr., Principal Chief
P.O. Box 948
Tahlequah, OK 74465

Re: Permit Application No. **2019-0607-TVR3**
American Electric Power (AEP)
Public Service Company of Oklahoma (PSO)
Northeastern Power Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Date Received: May 17, 2019

Dear Mr. Hoskin:

The Oklahoma Department of Environmental Quality (ODEQ), Air Quality Division (AQD), has received the Tier II/Tier III application referenced above. A Tier II/III application requires the facility provide a 30-day public comment period on the draft Tier II/III permit and a 20-day public comment period on a proposed Tier III permit at a public location within the county of the facility. The process requires the facility to notify the public by newspaper notice in a newspaper in the county of the proposed project. Since the proposed project falls within your Tribal jurisdiction, AQD is providing this direct notice. This letter notification is in addition to the newspaper notice.

Copies of draft permits and comment opportunities are also provided to the public on the ODEQ website at the following location:

<https://www.deq.ok.gov/air-quality-division/air-permits/public-participation-issued-permits/>

If you prefer a copy of the draft and/or proposed permit, or direct notification by letter for any remaining public comment opportunities, if applicable, on the referenced permit action, please notify me by e-mail at phillip.fielder@deq.ok.gov, or by letter at:

Department of Environmental Quality, Air Quality Division
Attn: Phillip Fielder, Chief Engineer
707 N Robinson
Oklahoma City, OK, 73102

Thank you for your cooperation. If you have any questions, I can also be contacted at (405) 702-4185.

Sincerely,



Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

May 31, 2022

Muscogee Creek Nation
Attn: David Hill, Principal Chief
P.O. Box 580
Okmulgee, OK 74447

Re: Permit Application No. **2019-0607-TVR3**
American Electric Power (AEP)
Public Service Company of Oklahoma (PSO)
Northeastern Power Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Date Received: May 17, 2019

Dear Mr. Hill:

The Oklahoma Department of Environmental Quality (ODEQ), Air Quality Division (AQD), has received the Tier II/Tier III application referenced above. A Tier II/III application requires the facility provide a 30-day public comment period on the draft Tier II/III permit and a 20-day public comment period on a proposed Tier III permit at a public location within the county of the facility. The process requires the facility to notify the public by newspaper notice in a newspaper in the county of the proposed project. Since the proposed project falls within your Tribal jurisdiction, AQD is providing this direct notice. This letter notification is in addition to the newspaper notice.

Copies of draft permits and comment opportunities are also provided to the public on the ODEQ website at the following location:

<https://www.deq.ok.gov/air-quality-division/air-permits/public-participation-issued-permits/>

If you prefer a copy of the draft and/or proposed permit, or direct notification by letter for any remaining public comment opportunities, if applicable, on the referenced permit action, please notify me by e-mail at phillip.fielder@deq.ok.gov, or by letter at:

Department of Environmental Quality, Air Quality Division
Attn: Phillip Fielder, Chief Engineer
707 N Robinson
Oklahoma City, OK, 73102

Thank you for your cooperation. If you have any questions, I can also be contacted at (405) 702-4185.

Sincerely,



Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

Attn: Daryll Jackson, VP, PSO Generating Assets
American Electric Power
P.O. Box 399
Oologah, OK 74053

Re: Permit Application No. **2019-0607-TVR3**
PSO Northeastern Station (Facility ID: 212)
Section 4, T22N, R15E, Rogers County, Oklahoma
Permit Writer: Iftekhar Hossain

Dear Mr. Jackson:

Air Quality Division has completed the initial review of your permit application referenced above. This application has been determined to be a **Tier II**. In accordance with 27A O.S. § 2-14-302 and OAC 252:004-7-13(c) the enclosed draft permit is now ready for public review. The requirements for public review 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 in this matter. If we may be of further service, or you have any questions about this permit, please contact the permit writer at Iftekhar.hossain@deq.ok.gov or me at (405) 702-4100.

Sincerely,



Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

Enclosures

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 NOTICE on page 2.

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., significant modification to a Title V permit or Title V/Title V renewal permit)... 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 operating 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: <http://www.deq.ok.gov/>

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: , which represents (identify the emissions change involved in the modification), or add: . The modification will not result in a change in emissions]

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.

In addition to the public comment opportunity offered under this notice, this draft permit is subject to U.S. Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 70.8.

If the Administrator (EPA) does not object to the proposed permit, the public has 60 days following the Administrator's 45-day review period to petition the Administrator to make such an objection as provided in 40 CFR 70.8(d) and in OAC 252:100-8-8(j).

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://www.deq.ok.gov/>.

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
9-10-21

ACFM	Actual Cubic Feet per Minute	GEP	Good Engineering Practice
AD	Applicability Determination	GHG	Greenhouse Gases
AFRC	Air-to-Fuel Ratio Controller	GR	Grain(s) (gr)
API	American Petroleum Institute		
ASTM	American Society for Testing and Materials	H₂CO	Formaldehyde
		H₂S	Hydrogen Sulfide
		HAP	Hazardous Air Pollutants
BACT	Best Available Control Technology	HC	Hydrocarbon
BAE	Baseline Actual Emissions	HCFC	Hydrochlorofluorocarbon
BBL	Barrel(s)	HFR	Horizontal Fixed Roof
BHP	Brake Horsepower (bhp)	HON	Hazardous Organic NESHAP
BTU	British thermal unit (Btu)	HP	Horsepower (hp)
		HR	Hour (hr)
C&E	Compliance and Enforcement		
CAA	Clean Air Act	I&M	Inspection and Maintenance
CAM	Compliance Assurance Monitoring	IBR	Incorporation by Reference
CAS	Chemical Abstract Service	ICE	Internal Combustion Engine
CAAA	Clean Air Act Amendments		
CC	Catalytic Converter	LAER	Lowest Achievable Emission Rate
CCR	Continuous Catalyst Regeneration	LB	Pound(s) [Mass] (lb, lbs, lbm)
CD	Consent Decree	LB/HR	Pound(s) per Hour (lb/hr)
CEM	Continuous Emission Monitor	LDAR	Leak Detection and Repair
CFC	Chlorofluorocarbon	LNG	Liquefied Natural Gas
CFR	Code of Federal Regulations	LT	Long Ton(s) (metric)
CI	Compression Ignition		
CNG	Compressed Natural Gas	M	Thousand (Roman Numeral)
CO	Carbon Monoxide or Consent Order	MAAC	Maximum Acceptable Ambient Concentration
COA	Capable of Accommodating	MACT	Maximum Achievable Control Technology
COM	Continuous Opacity Monitor	MM	Prefix used for Million (Thousand-Thousand)
D	Day	MMBTU	Million British Thermal Units (MMBtu)
DEF	Diesel Exhaust Fluid	MMBTUH	Million British Thermal Units per Hour (MMBtu/hr)
DG	Demand Growth	MMSCF	Million Standard Cubic Feet (MMscf)
DSCF	Dry Standard (At Standard Conditions) Cubic Foot (Feet)	MMSCFD	Million Standard Cubic Feet per Day
		MSDS	Material Safety Data Sheet
EGU	Electric Generating Unit	MWC	Municipal Waste Combustor
EI	Emissions Inventory	MWe	Megawatt Electrical
EPA	Environmental Protection Agency	NA	Nonattainment
ESP	Electrostatic Precipitator	NAAQS	National Ambient Air Quality Standards
EUG	Emissions Unit Group	NAICS	North American Industry Classification System
EUSGU	Electric Utility Steam Generating Unit	NESHAP	National Emission Standards for Hazardous Air Pollutants
		NH₃	Ammonia
FCE	Full Compliance Evaluation	NMHC	Non-methane Hydrocarbon
FCCU	Fluid Catalytic Cracking Unit	NGL	Natural Gas Liquids
FESOP	Federally Enforceable State Operating Permit	NO₂	Nitrogen Dioxide
FIP	Federal Implementation Plan	NO_x	Nitrogen Oxides
FR	Federal Register	NOI	Notice of Intent
		NSCR	Non-Selective Catalytic Reduction
GACT	Generally Achievable Control Technology		
GAL	Gallon (gal)		
GDF	Gasoline Dispensing Facility		

NSPS	New Source Performance Standards	SNCR	Selective Non-Catalytic Reduction
NSR	New Source Review	SO₂	Sulfur Dioxide
		SO_x	Sulfur Oxides
O₃	Ozone	SOP	Standard Operating Procedure
O&G	Oil and Gas	SRU	Sulfur Recovery Unit
O&M	Operation and Maintenance		
O&NG	Oil and Natural Gas	T	Tons
OAC	Oklahoma Administrative Code	TAC	Toxic Air Contaminant
OC	Oxidation Catalyst	TEG	Triethylene Glycol
		THC	Total Hydrocarbons
PAH	Polycyclic Aromatic Hydrocarbons	TPY	Tons per Year
PAE	Projected Actual Emissions	TRS	Total Reduced Sulfur
PAL	Plant-wide Applicability Limit	TSP	Total Suspended Particulates
Pb	Lead	TV	Title V of the Federal Clean Air Act
PBR	Permit by Rule		
PCB	Polychlorinated Biphenyls	µg/m³	Micrograms per Cubic Meter
PCE	Partial Compliance Evaluation	US EPA	U. S. Environmental Protection Agency
PEA	Portable Emissions Analyzer		
PFAS	Per- and Polyfluoroalkyl Substance	VFR	Vertical Fixed Roof
PM	Particulate Matter	VMT	Vehicle Miles Traveled
PM_{2.5}	Particulate Matter with an Aerodynamic Diameter <= 2.5 Micrometers	VOC	Volatile Organic Compound
		VOL	Volatile Organic Liquid
PM₁₀	Particulate Matter with an Aerodynamic Diameter <= 10 Micrometers	VRT	Vapor Recovery Tower
		VRU	Vapor Recovery Unit
POM	Particulate Organic Matter or Polycyclic Organic Matter	YR	Year
ppb	Parts per Billion		
ppm	Parts per Million	2SLB	2-Stroke Lean Burn
ppmv	Parts per Million Volume	4SLB	4-Stroke Lean Burn
ppmvd	Parts per Million Dry Volume	4SRB	4-Stroke Rich Burn
PSD	Prevention of Significant Deterioration		
psi	Pounds per Square Inch		
psia	Pounds per Square Inch Absolute		
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		
SCR	Selective Catalytic Reduction		
SER	Significant Emission Rate		
SI	Spark Ignition		
SIC	Standard Industrial Classification		
SIP	State Implementation Plan		